COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recordings of the evidentiary hearing conducted April 30 – May 2, 2012 in this proceeding;

- Certifications of the accuracy and correctness of the digital video recordings;

- All exhibits introduced at the evidentiary hearing conducted April 30 – May 2, 2012 in this proceeding;

- The written logs listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recordings of the evidentiary hearing conducted April 30 – May 2, 2012.

A copy of this Notice, the certifications of the digital video records, exhibit lists, and hearing logs have been served by first class mail upon all persons listed at the end of this Notice. Parties desiring electronic copies of the digital video recordings of the hearing in Windows Media format may download copies at:

http://psc.ky.gov/av_broadcast/2011-00401/2011-00401_30Apr12_Inter.asx

http://psc.ky.gov/av_broadcast/2011-00401/2011-00401_01May12_Inter.asx

http://psc.ky.gov/av_broadcast/2011-00401/2011-00401_02May12_Inter.asx

Parties wishing annotated digital video recordings may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for copies of these recordings.

The exhibits introduced at the evidentiary hearing may be downloaded at http://psc.ky.gov/pscscf/2011%20cases/2011-00401/.

Done at Frankfort, Kentucky, this 16th day of May 2012.

Linda Faulkner

Linda Faulkner
Director, Filings Division
Public Service Commission of Kentucky

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

CERTIFICATE

I, Kathy Gillum, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on **April 30, 2012;** (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on 3 consecutive days, April 30, 2012, May 1, 2012 and May 2, 2012 separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of **April 30, 2012** (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of **April 30, 2012** (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of **April 30, 2012** (excluding any confidential segments) and the time at which each occurred.

Given this 8th day of May, 2012.

Kathy Gillum

Kathy Gillum, Notary Public
State at Large
My commission expires: Sept 3, 2013

Case History Log Report

Case Number: 2011-00401_30Apr12

Case Title: Kentucky Power Company (Environmental Surcharge)
Case Type: Other
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Date: 4/30/2012
Location: Default Location
Judge: David Armstrong, Jim Gardner
Clerk: Kathy Gillum
Bailiff:

Event Time	Log Event	
10:05:59 AM	Case Started	
10:06:03 AM	Preliminary Remarks	
10:07:29 AM	Introductions	
	Note: Kathy Gillum	Mark Overstreet, Ken Gish, Hector Garcia for KY Power; Mike Kurtz for KIUC; Dennis Howard, Jennifer Hans, and Lawrence Cook for the Attorney General; Kristin Henry, Joe Childers, and Shannon Fisk, for SC; Faith Burns and Quang Nguyen for the Commission. Public notice has been given, no outstanding motions.
10:09:50 AM	Joe Childers (SC)	
	Note: Kathy Gillum	Mr. Childers states that it was his understanding that the witnesses will be called out of order. He objects to it.
10:10:29 AM	Mark Overstreet	
	Note: Kathy Gillum	Objection is Moot.
10:10:45 AM	Quang Nguyen (PSC)	
	Note: Kathy Gillum	PSC outlines that KY Power will call all of the witnesses in one batch.
10:11:13 AM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman states that the non-confidential testimony would be heard first, then the confidential testimony.
10:11:38 AM	Mark Overstreet (Ky Power)	
10:11:54 AM	Chairman Armstrong	
10:12:22 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states that the confidential segment is limited unless the Intervenors have questions regarding confidential materials. .
10:12:34 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Ms. Henry objects to confidential segment being at the end instead of following the witness.
10:13:18 AM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman states that the confidential segment will be at the end of testimonies.
10:13:35 AM	Public Comments	
	Note: Kathy Gillum	No members of the public present for comment.

10:14:08 AM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman states that the official record is the video.
10:14:35 AM	Witness, Ranie Wohnhas (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet.
10:15:19 AM	Examination by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Qualification of witness by Mark Overstreet. Witness adopts pre-filed testimony and responses to Data Requests.
10:15:45 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Mr. Howard states that the Intervenors may question witnesses out of order.
10:16:04 AM	Examination by Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding pages 8 thru 10 of direct testimony.
10:27:42 AM	Exhibit OAG 1	
	Note: Kathy Gillum	Document titled Notice of Filing of Supplemental Response to Identified Data Requests filed by Kentucky Power on March 9, 2012 (AG-1-26) introduced by Dennis Howard and marked as OAG Exhibit 1.
10:28:48 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding OAG Exhibit 1, page 2. Questions regarding credit (financial) metrics. Questions regarding the public hearings conducted prior to the hearing.
10:41:00 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet objects that counsel is asking for hearsay since the public hearings were not under oath.
10:41:30 AM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman Armstrong states that since the witness attending all 4 public hearings, he would let him answer the question.
10:41:57 AM	Ranie Wohnhas (Ky Power)	
	Note: Kathy Gillum	Witness summarizes what he heard from the public at the public hearings.
10:43:05 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding witness' awareness of past increases of Ky Power. Questions regarding Notice to Customers. Mr. Howard asked if an Amended Notice went out to ratepayers.
10:46:50 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Mr. Howard requests to admit OAG Exhibit 1 into the record.
10:47:52 AM	Exhibit OAG 2	
	Note: Kathy Gillum	Document titled, Notice of Filing of Supplemental Response to Identified Data Request filed Feb. 22, 2012 by Ky Power introduced by Dennis Howard OAG and marked as OAG Exhibit 2.
10:48:25 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding page 2 of OAG Exhibit 2. Questions regarding response to PSC 1-20. Mr. Howard states that he is trying to get what the cost to the ratepayer would be. Questions regarding Mr. Kollen's testimony as to a future rate case. Witness asked for an opinion as to a base rate case. Witness stated "no, that's why we're doing the ECR. Questions regarding page 9 of Mr. Kollen's Direct Testimony. Questions regarding the average impact on the residential bill. Questions regarding the financial status of the customer base.
11:10:11 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Mr. Howard requests to admit OAG Exhibit 2 into the record.

11:11:56 AM	Exhibit OAG 3	
	Note: Kathy Gillum	Map indicating Counties in AEP Service Area Percent of Persons in Poverty 2010, introduced by Dennis Howard (OAG) and marked as OAG Exhibit 3.
11:12:32 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding economically feasibility study.
11:14:53 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states that he is not sure what Mr. Howard meant by economically feasibility study.
11:16:01 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Mr. Howard brings up a prior Commission case using the Economically Feasibility Standard.
11:17:51 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: Objects to the line of questioning. States that the Econ. Feasbility Stnadard has no bearing on this particular question when there is a legal requirement that this be done.
11:18:24 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	States that the Commission has clearly articulated the standard that had to be met.
11:18:57 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	States that the question here is, we are required by law to do this...
11:19:59 AM	Chairman Armstrong (PSC)	
	Note: Kathy Gillum	Chairman states that Mr. Howard is going a little far afield with questioning.
11:20:14 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Requests to admit OAG Exhibit 3.
11:21:07 AM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding FERC Form 1.
11:24:36 AM	Exhibit KIUC 1	
	Note: Kathy Gillum	Document titled, Kentucky Power Company $/KWh, introduced by Mike Kurtz, KIUC, and marked as KIUC Exhibit 1. (info from FERC Form 1)
11:25:42 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding KIUC Exhibit 1.
11:26:33 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet asks if this Chart is part of the FERC Form 1?
11:27:17 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz states that this Chart puts the data from the FERC Form 1 into a Chart.
11:29:02 AM	Exhibit KIUC 2	
	Note: Kathy Gillum	Responses to PSC 1st Data Request, Item Nos. 82 and 83; and Response to Sierra Club's 1st Data Request Item No. 16, introduced by Mike Kurtz, KIUC and marked as KIUC Exhibit 2.
11:29:32 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding the net benefit to the local economy.
11:32:22 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet objects and asks Mr. Kurtz not yell at his witness.
11:33:03 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding amounts of coal from Kentucky and from W. Virginia.
11:38:34 AM	Exhibit KIUC 3	
	Note: Kathy Gillum	Document titled, 11th Edition, Pocket Guide, Kentucky Coal Provides, Jobs, Energy, Tax Revenue and Economic Growth, initroduced by Mike Kurtz (KIUC) and marked as KIUC Exhibit 3.

11:39:16 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding KIUC Exhibit 3.
11:40:48 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Vice Chair Gardner asks: Is that just Eastern Kentucky coal that you are talking about.
11:41:41 AM	Mike Kurtz (KIUC)	
11:43:49 AM	Exhibit KIUC 4	
	Note: Kathy Gillum	Responses to PSC 3rd Data Requests dated March 14, 2012, Item No. 17, introduced by Mike Kurtz and marked as KIUC Exhibit 4.
11:44:29 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding KIUC Exhibit 4.
11:45:39 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: Mr. Overstreet objected to a statement by Mr. Kurtz regarding trying to influence the Commission.
11:45:53 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding page 18 of KIUC Exhibit 4 (letter writing campaign). Questions regarding environmental investments, and pre-taxed rate of return.
11:52:30 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: That inaccurately states the application..
11:52:57 AM	Mike Kurtz (KIUC)	
11:53:22 AM	Exhibit KIUC 5	
	Note: Kathy Gillum	Document titled, AEP 46th EEI Financial Conference Presentation, Orlando, Florida, dated November 8, 2011, introduced by Mike Kurtz, KIUC and marked as KIUC Exhibit 5.
11:53:55 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding growing investments. Questions regarding purchased power strategy. Questions regarding PSC 2nd DR, Item 1. Questions regarding pool agreement. (witness states agreement was withdrawn)
12:02:39 PM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: Mr. Overstreet states that there is no proposal, it was withdrawn.
12:03:14 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding if it is Ky Power's intent to take 20% of Mitchell Unit. Questions regarding pool agreement filed with FERC and withdrawn. (energy sharing). Questions regarding page 11 of witness' direct testimony. Questions regarding page 9, line 3 of direct testimony. Questions regarding the "least cost option". Questions regarding PSC DR 4, Item 1.
12:23:24 PM	Lunch Break	
12:23:34 PM	Case Recessed	
1:32:58 PM	Case Started	
1:33:05 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz moves to admit KIUC Exhibits 1 thru 5 into the record.
1:33:19 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet stated that they had no objection except for the 1st page of 1.
1:33:27 PM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Mr. Howard stated they would have additional questions under confidentiality.
1:33:40 PM	Chairman Armstrong	

1:33:48 PM	Larry Cook (OAG)	
	Note: Kathy Gillum	Mr. Cook requests to ask questions of the witness prior to Sierra Club.
1:34:08 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Ms. Henry states that it is acceptable for the OAG to question the witness prior to her.
1:34:23 PM	Larry Cook (OAG)	
	Note: Kathy Gillum	Questions regarding regulatory policy issues around the state. Questions regarding W.Va. regulation.
1:36:55 PM	Examination by Kristin Henry (SC)	
1:37:15 PM	Exhibit SC 1	
	Note: Kathy Gillum	Responses to PSC 4th Data Requests dated April 2, 2012, Item No. 1 introduced by Kristin Henry (SC) and marked as SC Exhibit 1.
1:38:19 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding page 4 of SC Exhibit 1.
1:40:15 PM	Exhibit SC 2	
	Note: Kathy Gillum	Document titled, American Electric Power, 2010 AEP-East Integrated Resource Plan introduced by Kristin Henry (SC) and marked as SC Exhibit 2.
1:40:32 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	
1:44:27 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet asks for Ms. Henry to specify the time period of the questioning.
1:44:58 PM	Kristin Henry (SC)	
1:46:29 PM	Exhibit (Temporarily Stricken)	
	Note: Kathy Gillum	This Exhibit was not introduced because it contained confidential information. Will be introduced later in hearing during confidential mode.
1:48:42 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding Data Requests, page 2. Questions regarding direct testimony of witness, page 14, line 21. Questions regarding page 15, lines 1-4.
1:53:22 PM	Exhibit SC 3	
	Note: Kathy Gillum	Response to PSC 1st Data Requests dated January 13, 2012, Item No. 91, introduced by Kristin Henry and marked as SC Exhibit 3.
1:55:27 PM	Exhibit SC 4	
	Note: Kathy Gillum	Response to PSC 1st Data Request dated January 13, 2012, Item 89, introduced by Kristin Henry and marked as SC Exhibit 4.
1:56:11 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 4.
2:01:04 PM	Exhibit SC 5	
	Note: Kathy Gillum	Response to KIUC's 1st Data Request, dated January 13, 2012, Item No. 28, introduced by Kristin Henry and marked as SC Exhibit 5.
2:02:47 PM	Kristin Henry (SC)	
2:03:04 PM	Exhibit SC 6	
	Note: Kathy Gillum	Responses to Sierra Club's 1st Data Requests dated January 13, 2012, Item No. 17 introduced by Kristin Henry and marked as SC Exhibit 6.
2:04:09 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding Response H.

2:04:52 PM	Exhibit SC 7	
	Note: Kathy Gillum	Responses to Sierra Club's Supplemental Data Requests dated February 8, 2012 Item No. 16 introduced by Kristin Henry and marked as SC Exhibit 7.
2:04:57 PM	Kristin Henry (SC)	
2:10:46 PM	Exhibit SC 8	
	Note: Kathy Gillum	Response to Sierra Club Supplemental Data Requests dated February 8, 2012, Item 18 introduced by Kristin Henry and marked as SC Exhibit 8.
2:11:27 PM	Kristin Henry (SC)	
2:15:48 PM	Examination by Faith Burns (PSC)	
2:16:39 PM	Exhibit PSC 1	
	Note: Kathy Gillum	Document titled, 300 American Electric Power, Electric Operation and Maintenance Expenses - 1. Power Production (Ref. Pg. 320) introduced by Faith Burns (PSC) and marked as PSC Exhibit 1.
2:18:23 PM	Data Request (PSC)	
	Note: Kathy Gillum	Data Request: Calculation of approximate amounts of coal burned; the percentage of coal burned and the cost allocation for 2010.
2:20:26 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding Item 62 of PSC 1st D.R. regarding low sulfur coal. Ms. Burns moves to admit PSC Exhibit 1 into the record. No objections. Questions regarding Ky Power's last rate case. Questions regarding future rate increases. Questions regarding page 12 of direct testimony of the witness. Questions regarding Rockport Plant; Tanner's Creek (Indiana); Amos Plant (Ohio). Witness answers by referring to Lila Munsey's testimony, line 2. Questions regarding page 4 of witness' Rebuttal Testimony. Questions regarding Page 4, of Rebuttal Testimony, lines 10 through 14.
2:41:12 PM	Data Request (PSC)	
	Note: Kathy Gillum	Provide expense for May, 2003 to determine if SCR costs were included.
2:42:37 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding PSC DR2, Item 20. Questions regarding risk assessment by using the Aurora Model. Questions regarding Big Sandy units regarding consent decree.
2:48:27 PM	Chairman Armstrong	
	Note: Kathy Gillum	Questions regarding consent decree. Was RFP done?
2:54:47 PM	Vice-Chair Gardner	
	Note: Kathy Gillum	Questions regarding where the coal mines are located. Questions regarding depreciation. Witness states that the terms where in the 20 to 25 year timeframe.
2:58:53 PM	Data Request (PSC)	
	Note: Kathy Gillum	Vice Chair Gardner requested the percentage in dollar amounts of depreciation of the plants and the period of time.
2:59:44 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding the relationship between AEP and sister companies. Questions regarding the power pool. Questions regarding costs not included in this application, and costs that are included.
3:21:15 PM	Data Request (PSC)	
	Note: Kathy Gillum	Vice Chair requests the last time there was captial infusion, the purpose and the amount.

3:21:38 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding if it is an increase in the environmental surcharge or overall rate.
3:24:49 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding phase in approach.
3:25:43 PM	Re-Direct by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Questions regarding Ohio Power selling any of their capacity. Witness states that Option I is the least cost (scrub Unit 2). Questions regarding purchase power and the modeling stage of the process.
3:30:09 PM	Dennis Howard (OAG)	
3:31:34 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states that the info can be found in Exh. 3 of the Application.
3:32:01 PM	Dennis Howard (OAG)	
3:34:10 PM	Kristen Henry (SC)	
	Note: Kathy Gillum	Ms. Henry moves for all of her exhibits to be admitted into the record.
3:35:09 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding page 5, line 22 of Rebuttal Testimony. Questions regarding the costs of Phase I. Questions regarding PSC DR4, Item 1, page 4.
3:39:13 PM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: Witness is not an attorney.
3:39:38 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding being "energy long".
3:44:30 PM	Vice-Chair Gardner	
	Note: Kathy Gillum	Vice Chair Gardner asked what other options they have.
3:46:13 PM	Data Request (PSC)	
	Note: Kathy Gillum	Vice Chair requests the Early Termination Agreement date.
3:46:49 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding negotiations with respect fo Riverside.
3:47:21 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states that the information could contain confidential portions.
3:47:44 PM	Re-Direct by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Questions regarding the retirement of Big Sandy Unit 1. Questions regarding the plans to address the capacity deficient.
3:52:33 PM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding ECR Costs.
3:53:25 PM	Larry Cook (OAG)	
3:54:19 PM	Break	
3:54:47 PM	Case Recessed	
4:09:32 PM	Case Resumed	
4:49:38 PM	Public Mode On	
4:50:04 PM	Larry Cook (OAG)	
	Note: Kathy Gillum	Questions regarding Page 7059. Cost estimation for the chosen Option. Questions regarding 678.
4:58:25 PM	Witness Excused (Wohnhas)	
5:03:19 PM	Private Mode On	
5:45:17 PM	Public Mode On	

5:45:41 PM	Exhibit SC 11	
	Note: Kathy Gillum	Response to AG Supplemental Data Requests dated February 8, 2012, Item No. 6, introduced by Kristen Henry and marked as SC Exhibit 11.
5:49:02 PM	Witness Excused (Thomas)	
5:50:35 PM	Case Recessed	
6:04:44 PM	Case Resumed	
6:04:47 PM	Witness, Lila Munsey (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet.
6:05:31 PM	Examination by Mr. Gish (Ky Power)	
	Note: Kathy Gillum	Qualification of witness by Ken Gish. Witness corrects Direct Testimony. Item 20 concerning Revised Exhibit LP 13, line 16. Removal made a change to LPM 14, line 6, now .78%, and a total over all change 29.50%. Will provide revised sheets to all parties. Adopts re-filed testimony with corrections.
6:08:00 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding Exhibit 3 of corrected testimony. Questions regarding Line 2 - short term debt.
6:10:57 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Ms. Henry moves to admit SC 11 into record.
6:11:26 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding Item 23. Line 16 and 17, should they be eliminated. Witness states that was the correction. Questions regarding 1st DRs Item 45. Questions regarding PSC 2nd DR, Item 23, page 14-15. Questions regarding Item 23, Attachment 1, page 3.
6:19:56 PM	Data Request (PSC)	
6:20:06 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding long term fuel contracts.
6:20:57 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding Page 8 of testimony. Witness directs to LPM 6. Questions regarding the percentage of costs assigned to Ky Power.
6:26:31 PM	Chairman Armstrong	
	Note: Kathy Gillum	Questions regarding net impact.
6:27:36 PM	Data Request	
	Note: Kathy Gillum	Chairman Armstrong asked that the numbers be provided.
6:27:46 PM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding net effect on ratepayers.
6:28:39 PM	Witness Excused (Munsey)	
6:29:49 PM	Case Recessed	

Exhibit List Report

Case Number: 2011-00401_30Apr12

Case Title: Kentucky Power Company (Environmental Surcharge)
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Name	Description
KIUC Exhibit 1	Document titled, Kentucky Power Company $/KWh (info from FERC Form 1).
KIUC Exhibit 2	Responses to PSC 1st Data Request, Item Nos. 82 and 83; and Response to Sierra Club's 1st Data Request Item No. 16.
KIUC Exhibit 3	Document titled, 11th Edition, Pocket Guide, Kentucky Coal Provides, Jobs, Energy, Tax Revenue and Economic Growth
KIUC Exhibit 4	Responses to PSC 3rd Data Requests dated March 14, 2012, Item No. 17.
KIUC Exhibit 5	Document titled, AEP 46th EEI Financial Conference Presentation, Orlando, Florida, dated November 8, 2011
KIUC Exhibit 6	(Confidential Materials)
OAG Exhibit 1	Document titled Notice of Filing of Supplemental Response to Identified Data Requests filed by Kentucky Power on March 9, 2012 (AG-1-26).
OAG Exhibit 2	Document titled, Notice of Filing of Supplemental Response to Identified Data Request filed Feb. 22, 2012 by Ky Power
OAG Exhibit 3	Map indicating Counties in AEP Service Area Percent of Persons in Poverty 2010.
PSC Exhibit 1	Document titled, 300 American Electric Power, Electric Operation and Maintenance Expenses - 1. Power Production (Ref. Pg. 320)
SC Exhibit 1	Responses to PSC 4th Data Requests dated April 2, 2012, Item No. 1
SC Exhibit 10.	(Confidential Materials)
SC Exhibit 11	Response to AG Supplemental Data Requests dated February 8, 2012, Item No. 6.
SC Exhibit 2	Document titled, American Electric Power, 2010 AEP-East Integrated Resource Plan
SC Exhibit 3	Response to PSC 1st Data Requests dated January 13, 2012, Item No. 91.
SC Exhibit 4	Response to PSC 1st Data Request dated January 13, 2012, Item 89
SC Exhibit 5	Response to KIUC's 1st Data Request, dated January 13, 2012, Item No. 28
SC Exhibit 6	Responses to Sierra Club's 1st Data Requests dated January 13, 2012, Item No. 17
SC Exhibit 7	Responses to Sierra Club's Supplemental Data Requests dated February 8, 2012 Item No. 16.
SC Exhibit 8	Response to Sierra Club Supplemental Data Requests dated February 8, 2012, Item 18
SC Exhibit 9	(Confidential Materials)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	CASE NO. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF	)	
A CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

CERTIFICATE

I, Kathy Gillum, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on **May 1, 2012;** (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on 3 consecutive days, April 30, 2012, May 1, 2012 and May 2, 2012 separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of **May 1, 2012** (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of **May 1, 2012** (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of **May 1, 2012** (excluding any confidential segments) and the time at which each occurred.

Given this 11th day of May, 2012.

Kathy Gillum

Kathy Gillum, Notary Public
State at Large
My commission expires: Sept 3, 2013

Case History Log Report

Case Number: 2011-00401_01May12

Case Title: Kentucky Power Company (Environmental Surcharge)
Case Type: Other
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Date: 5/1/2012
Location: Default Location
Judge: David Armstrong, Jim Gardner
Clerk: Kathy Gillum
Bailiff:

Event Time	Log Event	
10:05:45 AM	Case Started	
10:05:54 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states that he does not object to Dr. Jeremy Fisher testifying out of turn due to scheduling conflicts.
10:06:20 AM	Dennis Howard (OAG)	
10:07:09 AM	Examination by Kristin Henry (SC)	
	Note: Kathy Gillum	Qualification of witness by Kristin Henry. Witness adopts pre-filed testimony and errata with updates. Witness makes update to captial costs.
10:08:49 AM	Exhibit SC 12	
	Note: Kathy Gillum	Exhibit: Direct Testimony of Jeremy Fisher dated 5-1-12 with redacted portions, introduced by Kristin Henry and marked as SC Exhibit 12.
10:11:04 AM	Examination by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Questions regarding revised supplemental testimony. Questions regarding modeling results. Questions regarding page 19 of Direct Testimony prior to revision, line 6. Questions regarding Page 18. Questions regarding long term resource modeling. Questions regarding the Aurora Modeling. Witness reads from Weaver Testimony page 48, beginning at line 3. Questions regarding Table 4, page 37 of Revised Testimony. Witness refers natural gas pricing questions to Mr. Hornby. Questions regarding coal demand and pricing. Questions regarding hydraulic fracturing.
10:34:24 AM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding revised supp. testimony line 21. Witness states that Lines 21 to 24 should be redacted. Questions regarding FERC filing and withdrawal. Questions regarding pool agreement.
10:37:03 AM	Examination by Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding the coal market.
10:38:08 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding inconsistency of the modeling. Witness refers to his Revised Supp. Testimony page 18, Table 1. Questions regarding capital costs.

10:06:48 AM	Witness, Jeremy Fisher (SC)	
	Note: Kathy Gillum	Witness called to testify by Sierra Club.
10:44:51 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet asks the witness to clarify that the redacted version of his revised testimony is meant to remove those portions from the testimony, not to make it confidential. Witness agrees.
10:46:10 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Witness explains why the testimony was revised or removed. Questions regarding Capital Expenses and Carrying Costs section. Questions regarding Strategist Modeling and Aurora Modeling. Witness explains the Strategist Model.
10:57:55 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz asks for clarification of last question and answer.
10:58:31 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Vice Chair Gardner repeats the question, and the witness repeats his answer.
10:59:47 AM	Re-Direct Examination by Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding the issues in the Motion to Compel. Witness explains his work at Symax. Questions regarding the Aurora Modeling. Questions regarding the Demand Risk in Weaver testimony. Questions regarding page 68 of the Revised Supp. Testimony. Witness states that Option 1 and 2 come in at essentially the same value.
11:06:18 AM	Examination by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Questions regarding calculations outside of the Strategist Model. Questions regarding Becker testimony pages 8, 9, 10.
11:08:05 AM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding what the witness means by demand. Witness states that it is energy demand. Witness refers to Mr. Hornby.
11:09:46 AM	Re-Direct by Kristen Henry (SC)	
11:10:22 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states that he did not make the statement in the way Ms. Henry stated in her question to the witness.
11:10:29 AM	Kristen Henry (SC)	
	Note: Kathy Gillum	Kristen Henry rephrases the question.
11:11:08 AM	Witness Excused (Fisher)	
11:11:20 AM	Witness, John McManus (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet (Ky Power).
11:11:56 AM	Examination by Hector Garcia (Ky Power)	
	Note: Kathy Gillum	Qualification of witness by Hector Garcia. Witness adopts pre-filed testimony.
11:13:45 AM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding page 17 of Direct Testimony, line 5. Question regarding Mr. Walton's timeline (document already a part of the record).
11:21:26 AM	Examination by Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding witness' testimony page 8.
11:22:41 AM	Data Request (PSC)	
	Note: Kathy Gillum	Ms. Burns requests the Names of the Units.

11:22:57 AM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding Response to PSC 1st DR Item 26, attachment 1, page 3, 4th paragraph. Questions regarding Response to PSC 3rd DR Item 9. Questions regarding Response to PSC 1st DR Item 5 (SO2 and nocs admissions). Questions regarding the EPA MACT Rule. Questions regarding mothballing the Big Sandy unit. Questions regarding length of idle time relating to the permit allowances.
11:39:20 AM	Examination by Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding carbon capture technology. Questions regarding cost of carbon capture under AEP study.
11:44:50 AM	Chairman Armstrong	
	Note: Kathy Gillum	Questions regarding Carbon Capture.
11:46:33 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding settlement with EPA, and its requirements. Questions regarding proposal to PSC without the EPA rules (CSPAR or MATS). Questions regarding dry sorbine injection. Questions regarding age of Rockport Units. Questions regarding the Coal Combusion Rule and the Clean Water Rule. Questions regarding why the company did not start initial phases prior to now.
12:09:01 PM	Chairman Armstrong	
	Note: Kathy Gillum	Questions regarding the Consent Decree.
12:12:09 PM	Examination by Kristen Henry (SC)	
	Note: Kathy Gillum	Questions regarding New Source Performance Standard. Questions regarding Consent Decree. Questions regarding additional future costs.
12:17:52 PM	Re-Direct by Hector Garcia (Ky Power)	
	Note: Kathy Gillum	Questions regarding scrubbing Big Sandy. Questions regarding Exhibit RLW-1
12:19:57 PM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding the retirement of the Big Sandy Plant. Questions regarding New Source Performance Standard.
12:23:48 PM	Examination by Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding mothballing a plant and then bringing it back on line.
12:24:23 PM	Kristen Henry (SC)	
	Note: Kathy Gillum	Questions regarding risks of Green House Gas Rules.
12:26:16 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding energy efficiency options.
12:29:13 PM	Chairman Armstrong	
12:30:17 PM	SC Exhibit 13 (Confidential)	
	Note: Kathy Gillum	Confidential materials.
12:31:31 PM	Case Recessed	
1:20:50 PM	Case Started	
1:21:15 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet calls Robert Walton to testify.
1:21:25 PM	Witness, Robert Walton (Ky Power)	
	Note: Kathy Gillum	Called to testify by Mark Overstreet .
1:22:05 PM	Examination by Ken Guish (Ky Power)l	
	Note: Kathy Gillum	Qualification of witness by Ken Gish (Ky Power). Witness adopts pre-filed testimony.
1:22:12 PM	Examination by Dennis Howard (OAG)	

1:24:44 PM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding Direct Testimony page 4.
1:26:14 PM	Exhibit KIUC 7	
	Note: Kathy Gillum	Document labeled RLW-1 introduced by Mike Kurtz and marked as KIUC Exhibit 7.
1:27:03 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding page 4, line 19 of Direct Testimony. Questions regarding page 5, line 23. Questions regarding page 6, line 7. Questions regarding Commission approval of project that may be cancelled. Questions regarding Phase I of the wet scrubber. Questions regarding Phase II start up date. Questions regarding air permit timeline. Questions regarding page 6, line 10. Questions regarding cost of the scrubber at Rockport. Questions regarding cost of coal ash disposal. Questions regarding Strategist Model.
1:51:26 PM	Examination by Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding dry scrubber evaluation. Questions relating to PSC Case No. 2002-00169. Questions regarding the Indiana PSC application and\or final order. Witness states that there is not a final order yet in the Indiana case.
1:54:26 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding PSC 1st DR, Item 35. Questions regarding the Mitchell facility and its compliance with the Utility MACT rule and CSPAR Rule. Questions regarding witness' involvement with Phase I. Witness states he got involved with Big Sandy in 2010.
2:02:45 PM	Data Request (PSC)	
	Note: Kathy Gillum	Vice Chair Gardner requests updates to PSC 3rd DR Item 10
2:03:51 PM	Re-Direct by Ken Gish (Ky Power)	
2:06:40 PM	Examination by Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding Direct Testimony, page 3, line 10.
2:14:41 PM	Ken Gish (Ky Power)	
2:14:54 PM	Dennis Howard (OAG)	
2:15:08 PM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman states that the witness may have already answered Mr. Howard's question.
2:15:15 PM	Robert Walton (Ky Power)	
	Note: Kathy Gillum	Witness explains what he has already stated.
2:15:48 PM	Chairman Armstrong	
	Note: Kathy Gillum	Questions regarding working with Mr. Weaver.
2:19:58 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding the difference between table top exercise and modeling.
2:22:28 PM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman asked, How many options were there?
2:23:02 PM	Witness Excused (Walton)	
2:23:14 PM	Witness, Scott Weaver (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet.
2:24:00 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Qualification of witness by Mark Overstreet. Correction to Direct Testimony, Page 51, line 19 - eliminate the word NOTat the end of the line. Witness adopts pre-filed testimony and responses to data requests.

2:26:10 PM	Examination by Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding Direct Testimony page 11, lines 7-8. Questions regarding Energy Efficiency Potential Study.
2:36:49 PM	Exhibit SC 14	
	Note: Kathy Gillum	Exhibit: Responses to SC 1st D.R. dated January 13, 2012, introduced by Shannon Fisk and marked as SC Exhibit 14.
2:37:29 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding which units would be offered to the AEP affiliates. Questions regarding the FERC filing.
2:43:43 PM	Exhibit SC 15	
	Note: Kathy Gillum	Exhibit: Direct Testimony of Philip J. Nelson in Support of AEP Ohio's Modified Electric Security Plan, introduced by Shannon Fisk and marked as SC Exhibit 15.
2:44:36 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding Philip Nelson testimony, page 4 (SC Exhibit 15). Mr. Fisk moves to enter SC 14 and 15 into the record. No objections. Questions regarding the Strategist Modeling Plan.
2:56:50 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Mr. Fisk moves to strike the analysis.
2:57:29 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states it was a sensitivity not an analysis and had no bearing on the application. It was not requested in discovery.
3:00:04 PM	Shannon Fisk (SC)	
3:00:28 PM	Mark Overstreet (Ky Power)	
3:00:59 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding page 20 of Direct Testimony. Questions regarding SCW-2, page 2. Questions regarding alternative scenerios. Questions regarding Dr. Fisher testimony, page 29. Witness states that he did not rebutt because he felt there was no need. Questions regarding pricing (CO2 v. Natural gas). Questions regarding SCW-1, page 11, Table 1-4. Questions regarding Dr. Fisher testimony, page 62, line 10. Questions regarding economical dispatch. Questions regarding Direct Testimony SCW-4.
3:37:12 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states, "It wasn't an analysis, it was a sensitivity".
3:37:44 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding modeling in the application. Questions regarding Rebuttal Testimony, lines 12-18. Questions regarding off-system sales. Questions regarding page 16. Questions regarding page 18 of Rebuttal Testimony.
3:55:17 PM	Case Recessed	
4:15:35 PM	Case Started	
4:15:42 PM	Case Recessed	
4:20:56 PM	Case Started	
4:21:09 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding page 48 of Direct Testimony. Questions regarding SCW-5. Questions regarding page 27 of Rebuttal Testimony. Questions regarding page 30 of Rebuttal Testimony. Questions regarding SCW-5 of Direct Testimony. Questions regarding SCW-5R. Questions regarding SCW-7R. Questions regarding Aurora Modeling.

4:55:51 PM	Exhibit SC 16	
	Note: Kathy Gillum	Document titled Indiana Michigan Power Company, Integrated Resource Planning Report to the Indiana Utility Regulatory Commission dated November 1, 2011, introduced by Shannon Fisk and marked as SC Exhibit 16.
4:56:10 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding Direct Testimony page 38, line 8 thru page 42. Questions regarding Page 38, line 12 and 13. Mr. Fisk moves to admit Exhibit 16 into the record.
5:07:52 PM	Exhibit SC 17	
	Note: Kathy Gillum	Document titled "Direct Testimony of Robert P. Powers in Support of AEP Ohio's Modified Electric Security Plan dated March 30, 2012, introduced by Shannon Fisk and marked as SC Exhibit 17.
5:11:10 PM	Exhibit SC 18	
	Note: Kathy Gillum	Document titled "Direct Testimony of Frank C. Graves in Support of AEP Ohio's Modified Electric Security Plan dated March 30, 2012, introduced by Shannon Fisk and marked as SC Exhibit 18.
5:13:10 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding Frank Graves testimony. Questions regarding Direct Testimony page 38.
5:22:01 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding sensitivity study.
5:23:55 PM	Chairman Armstrong	
	Note: Kathy Gillum	Chairman Armstrong requested the document (sensitivity study).
5:24:37 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Witness states that he has no knowledge of document or the figures and data. Witness states that this is a sensitivity looking at the retirement of Big Sandy. Witness states he does not support certain columns or figures in the document. Questions regarding page 13 of Rebuttal Testimony. Questions regarding the Strategist Model. Questions regarding Powers Direct Testimony page 21, line 20.
5:58:53 PM	Exhibit KIUC 8	
	Note: Kathy Gillum	Exhibit: Responses to PSC 4th DR Item 1 dated April 2, 2012 introduced by Mike Kurtz and marked as KIUC Exhibit 8.
5:59:08 PM	Exhibit KIUC 9	
	Note: Kathy Gillum	Exhibit: Document titled "Summary of Long-Term Comodity Price Forecast Scenarios (SCW-2), Introduced by Mike Kurtz and marked as KIUC Exhibit 9.
5:59:54 PM	Exhibit KIUC 10	
	Note: Kathy Gillum	Exhibit: Document labeled as Henry Hub, Dated 4/30/12, introduced by Mike Kurtz and marked as KIUC Exhibit 10.
6:01:00 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Moves to admit KIUC Exhibit 8, 9, and 10.
6:08:30 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Moves to admit 16 and 17.
6:08:56 PM	Exhibit KIUC 11	
	Note: Kathy Gillum	Exhibit: (Sensitivity document) titled, Big Sandy 2 UD Analysis Under FTCA_CSAPR Commodity Pricing. Mike Kurtz moves to admit sensitivity document.
6:11:35 PM	Dennis Howard (OAG)	
6:12:54 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding Ohio Commission documents. Questions regarding off-system sales.

6:16:04 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding Rockport and the Strategist Model. Question as to whether the age of the two facilities was included in the model.
6:26:09 PM	Case Recessed	
7:16:39 PM	Case Started	
7:16:48 PM	Re-Direct by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 18. Questions regarding absolute values.
7:20:11 PM	Examination by Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 18. Questions regarding Page 16, line 21. Questions regarding KIUC Exhibit 11. Witness states that he has not seen this document prior to a few hours ago.
7:26:18 PM	Exhibit SC 19	
	Note: Kathy Gillum	Exhibit: Response to KIUC 1st DR dated January 13, 2012, Item No. 28, introduced by Shannon Fisk and marked as SC Exhibit 19
7:26:32 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Questions regarding alternative assumptions.
7:29:38 PM	Private Mode On	
7:36:25 PM	Public Mode On	
7:36:58 PM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Moves to admit SC Exhibit 19 into the record. No objections.
7:37:04 PM	Witness, Stephen Baron (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet.
7:37:53 PM	Examination by Hector Garcia (Ky Power)	
	Note: Kathy Gillum	Qualification of witness by Hector Garcia. Witness adopts pre-filed testimony.
7:38:37 PM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding Page 2 of JRW-3.
7:41:48 PM	Mark Overstreet (Ky Power)	
7:42:00 PM	Dennis Howard (OAG)	
7:42:14 PM	Chairman Armstrong	
7:42:22 PM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding low equity cost rates. Witness answers 39. Witness answers 2 high numbers. Questions regarding eliminating numbers. Questions regarding WEA-5.
7:50:43 PM	Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding Page 7 of Rebuttal Testimony, line 4.
7:52:27 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding surcharge mechanism.
7:54:38 PM	Witness Excused (Baron)	
7:55:00 PM	Witness, Carl Bletzacker (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet.
7:55:42 PM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Qualification of the witness by Mark Overstreet. Witness adopts pre-filed testimony.
7:55:53 PM	Examination by Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding Wohnhas Testimony page 17, liines 5 thru10. Questions regarding page 7, line 3 of witness' Rebuttal Testimony. Questions regarding Dr. Fisher testimony page 36, lines 6-9.

8:10:05 PM	Exhibit SC 21	
	Note: Kathy Gillum	Exhibit: Response to SC 1st DR dated January 13, 2012, Item No. 45.
8:11:38 PM	Exhibit SC 22	
	Note: Kathy Gillum	Exhibit: Document (Graph) labeled as JIF 7-B, Reference case CO2 prices from other US Utilities, introduced by Kristin Henry and marked as SC Exhibit 22.
8:14:31 PM	Exhibit SC 23	
	Note: Kathy Gillum	Exhibit: Document titled Docket No. 2011-10-E, Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan, introduced by Kristin Henry and marked as SC Exhibit 23.
8:15:37 PM	Kristin Henry (SC)	
8:17:36 PM	Exhibit SC 24	
	Note: Kathy Gillum	Exhibit: Document titled, Integrated Resource Plan, TVA's Environmental & Energy Future, March 2011, introduced by Kristin Henry and marked as SC Exhibit 24.
8:19:29 PM	Examination by Kristin Henry (SC)	
	Note: Kathy Gillum	Kristin Henry moves to admit SC 21, 22, 23 and 24 into the record.
8:21:03 PM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objects to the question. Stated it was not a fair question.
8:21:39 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Witness states he would not agree with them. Questions regarding Rebuttal Testimony. Questions regarding SC Exhibit 22.
8:24:36 PM	Mark Overstreet (Ky Power)	
8:24:48 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding Rebuttal Testimony, page 11, lines 1 through 6. Kristin Henry moves to admit SC Exhibits 25, 26 and 27 into the record.
8:27:23 PM	Exhibit SC 25	
	Note: Kathy Gillum	Exhibit: END 12149, Bill sponsored by Senator Bingham, introduced by Kristin Henry and marked as SC Exhibit 25.
8:31:32 PM	Exhibit SC 26	
	Note: Kathy Gillum	Exhibit: Document titled, Analysis of Impacts of a Clean Energy Standard, dated November, 2011, introduced by Kristin Henry and marked as SC Exhibit 26.
8:31:47 PM	Exhibit SC 27	
	Note: Kathy Gillum	Exhibit: Document titled, Report - Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman, introduced by Kristin Henry and marked as SC Exhibit 27.
8:33:33 PM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding Aurora Modeling.
8:40:24 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding future gas prices.
8:44:21 PM	Exhibit KIUC 12	
	Note: Kathy Gillum	Exhibit: Document titled, Forward Power Prices (off peak), introduced by Mike Kurtz and marked as KIUC Exhibit 12.
8:44:32 PM	Exhibit KIUC 13	
	Note: Kathy Gillum	Exhibit: Document titled, Forward Power Prices (on peak), introduced by Mike Kurtz and marked as KIUC Exhibit 13.
8:47:13 PM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding locking in future prices.
9:01:04 PM	Examination by Faith Burns (PSC)	
	Note: Kathy Gillum	Questions regarding carbon dioxide.

9:02:57 PM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding changes in regulations.
9:05:31 PM	Witness Excused (Bletzacker)	
9:06:17 PM	Case Recessed	

Exhibit List Report

Case Number: 2011-00401_01May12

Case Title: Kentucky Power Company (Environmental Surcharge)
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Name	Description
KIUC Exhibit 10	Document labeled as Henry Hub, Dated 4/30/12
KIUC Exhibit 11	(Sensitivity document) titled, Big Sandy 2 UD Analysis Under FTCA_CSAPR Commodity Pricing
KIUC Exhibit 12	Document titled, Forward Power Prices (off peak)
KIUC Exhibit 13	Document titled, Forward Power Prices (on peak)
KIUC Exhibit 7	Document labeled RLW-1 introduced by Mike Kurtz and marked as KIUC Exhibit 7.
KIUC Exhibit 8	Responses to PSC 4th DR Item 1 dated April 2, 2012
KIUC Exhibit 9	Document titled "Summary of Long-Term Comodity Price Forecast Scenarios (SCW-2)
SC Exhibit 12	Direct Testimony of Jeremy Fisher dated 5-1-12 with redacted portions
SC Exhibit 13 (Confidential Materials)	
SC Exhibit 14	Responses to SC 1st D.R. dated January 13, 2012,
SC Exhibit 15	Direct Testimony of Philip J. Nelson in Support of AEP Ohio's Modified Electric Security Plan
SC Exhibit 16	Document titled Indiana Michigan Power Company, Integrated Resource Planning Report to the Indiana Utility Regulatory Commission dated November 1, 2011
SC Exhibit 17	Document titled "Direct Testimony of Robert P. Powers in Support of AEP Ohio's Modified Electric Security Plan dated March 30, 2012
SC Exhibit 18	Document titled "Direct Testimony of Frank C. Graves in Support of AEP Ohio's Modified Electric Security Plan dated March 30, 2012
SC Exhibit 19	Response to KIUC 1st DR dated January 13, 2012, Item No. 28
SC Exhibit 20 (Confidential Materials)	
SC Exhibit 21	Response to SC 1st DR dated January 13, 2012, Item No. 45
SC Exhibit 22	Document (Graph) labeled as JIF 7-B, Reference case CO2 prices from other US Utilities
SC Exhibit 23	Document titled Docket No. 2011-10-E, Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan
SC Exhibit 24	Document titled, Integrated Resource Plan, TVA's Environmental & Energy Future, March 2011
SC Exhibit 25	END 12149, Bill sponsored by Senator Bingaman,
SC Exhibit 26	Document titled, Analysis of Impacts of a Clean Energy Standard, dated November, 2011
SC Exhibit 27	Document titled, Report - Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman,

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	) CASE NO. 2011-00401

CERTIFICATE

I, Kathy Gillum, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on **May 2, 2012;** (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on 3 consecutive days, April 30, 2012, May 1, 2012 and May 2, 2012 separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of **May 2, 2012** (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of **May 2, 2012** (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of **May 2, 2012** (excluding any confidential segments) and the time at which each occurred.

Given this 16th day of May, 2012.

Kathy Gillum

Kathy Gillum, Notary Public
State at Large
My commission expires: Sept 3, 2013

Case History Log Report

Case Number: 2011-00401_02May12

Case Title: Kentucky Power Company (Environmental Surcharge)
Case Type: Other
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Date: 5/2/2012
Location: Default Location
Judge: David Armstrong, Jim Gardner
Clerk: Kathy Gillum
Bailiff:

Event Time	Log Event	
9:40:20 AM	Case Started	
9:40:23 AM	Mark Overstreet (Ky Power)	
9:40:33 AM	Witness, Mark Becker (Ky Power)	
	Note: Kathy Gillum	Witness called to testify by Mark Overstreet.
9:41:02 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Qualification of witness by Mark Overstreet. Witness adopts pre-filed testimony.
9:41:33 AM	Examination by Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding audit process. Questions regarding Strategist files.
9:43:12 AM	Exhibit SC 28	
	Note: Kathy Gillum	Exhibit: Response to SC 1st DR dated January 13, 2012, Item 37, introduced by Kristin Henry and marked as SC Exhibit 28.
9:43:24 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Ms. Henry stated Exhibit 29, but actually is Exhibit 28. She corrects later.
9:46:10 AM	Exhibit SC 29	
	Note: Kathy Gillum	Exhibit: Response to SC 1st DR dated January 13, 2012, Item 69, introduced by Kristin Henry and marked as SC Exhibit 29
9:46:22 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 29.
9:47:43 AM	Exhibit SC 30	
	Note: Kathy Gillum	Exhibit: Response to KIUC 1st DR dated January 13, 2012, Item 28, introduced by Kristin Henry and marked as SC Exhibit 30
9:48:42 AM	Exhibit SC 31	
	Note: Kathy Gillum	Exhibit: Response to PSC 1st DR dated January 13, 2012, Item 48, introduced by Kristin Henry and marked as SC Exhibit 31
9:52:01 AM	Exhibit SC 32	
	Note: Kathy Gillum	Exhibit: Response to SC Supp DR dated Feb 8, 2012, Item 4, introduced by Kristin Henry and marked as SC Exhibit 32
9:52:50 AM	Exhibit SC 33	
	Note: Kathy Gillum	Exhibit: Responses to SC Supp. DR dated Feb 8, 2012, Item 34, introduced by Kristin Henry and marked as SC Exhibit 33

9:54:16 AM	Exhibit SC 34	
	Note: Kathy Gillum	Exhibit: Response to SC Supp DR dated Feb 8, 2012, Item 35, introduced by Kristin Henry and marked as SC Exhibit 34
9:56:25 AM	Exhibit SC 35	
	Note: Kathy Gillum	Exhibit: Response to SC Supp DR dated Feb 8, 2012, Item 39, introduced by Kristin Henry and marked as SC Exhibit 35
9:59:01 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding Strategist Model. Questions regarding the changes that needed to be made to the Strategist Model. Witness states that the changes involved the Reserve Margin Logic. Questions regarding the fixed O & M category.
10:05:06 AM	Exhibit SC 36	
	Note: Kathy Gillum	Exhibit: Copy of Ms. Wilson's notes regarding conversation with Mr. Becker introduced by Kristen Henry and marked as SC Exhibit 36
10:08:36 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 36. Witness states that his understanding of the conversation is different from Ms. Wilson's
10:09:37 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: Compound question.
10:10:09 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 32. Questions regarding capital costs in relation to the Strategist Model. Questions regarding CER. Questions regarding resource options to each alternative.
10:19:50 AM	Examination by Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding KIUC Exhibit 11.
10:20:32 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet requests to hand the Exhibit to the witness.
10:20:42 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Questions regarding retirement of Big Sandy Units.
10:21:48 AM	Objection by Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Objection: There's no ... (Mr. Kurtz interrupts to rephrase)
10:22:02 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	States he will rephrase. Questions regarding preparation of documents.
10:22:52 AM	Objection by Mark Overstreet	
	Note: Kathy Gillum	Objection: Badgering the witness.
10:23:02 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz states he will rephrase. Questions regarding changes to the model.
10:25:42 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding relationship with Mr. Weaver. Questions regarding PJM being a summer peaking system and Kentucky Power is a winter peaking system. Questions regarding purchase power in relation to peaks. Questions regarding input into the Model. Questions regarding gas prices in the Model.
10:31:20 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	No Re-Direct
10:31:32 AM	Examination by Kristin Henry (SC)	
	Note: Kathy Gillum	Questions regarding SC Exhibit 1, page 2, 2nd to last sentence in paragraph.
10:34:17 AM	Witness Excused (Becker)	
10:34:33 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Discussion regarding order of witnesses.

10:35:19 AM	Witness, Dr. J. Randall Woolridge	
	Note: Kathy Gillum	Witness called to testify by Dennis Howard (OAG). Qualification of witness by Dennis Howard (OAG). Witness adopts pre-filed testimony.
10:36:50 AM	Witness Excused (Woolridge)	
	Note: Kathy Gillum	There was no cross examination for this witness.
10:37:22 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz states that they have 3 witnesses, all of whom have filed pre-filed testimony.
10:37:34 AM	Witness, Lane Kollen (KIUC)	
10:37:56 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Qualification of witness by Mike Kurtz. Witness adopts pre-filed testimony with corrections. Corrections: page 11, line 12, insert, or $80 million dollars if the company's share of OSS margins is removed,. Line 13, insert the same phrase except the amount is $151 million dollars. Page 22, line 16 and 17, strike apostrophe, strike president and CEO. Mike Kurtz passes out an insertion to witness' testimony.
10:42:51 AM	Examination by Quang Nguyen (PSC)	
	Note: Kathy Gillum	Questions regarding allocations. Questions regarding page 18 of pre-filed testimony. Questions regarding the delay option. Questions regarding page 28 of testimony, 1st question at the top of the page. Questions regarding bilateral agreements. Questions regarding the impact of retirements of coal fired plants. Questions regarding purchase power option.
10:54:10 AM	Examination by Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding percentage of increase. Questions regarding the ECR Component. Questions regarding page 9 of testimony.
10:57:56 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding off system sales. Witness refers to his corrections to his pre-filed testimony. Questions regarding recovery of costs for certain options.
11:03:41 AM	Witness Excused (Kollen)	
11:03:56 AM	Witness, Stephen Baron (KIUC)	
	Note: Kathy Gillum	Witness called to testify by Mike Kurtz (KIUC).
11:04:17 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Qualification of witness by Mike Kurtz. Witness adopts pre-filed testimony with correction, Correction: page 14, line 12, after the words should be, the word allocated should be inserted.
11:05:34 AM	Examination by Ken Gish	
	Note: Kathy Gillum	Questions regarding allocation factor. Witness explains that it depends on load factor.
11:08:27 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Questions regarding where the schools fall in the tariffs.
11:09:22 AM	Data Request (OAG)	
	Note: Kathy Gillum	Provide answer if the schools did fall into the medium general service; and the numbers similiar to those in the chart.
11:09:52 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet stated he will provide to Mike Kurtz and Mr. Kurtz can make them availabvle to Mr. Baron.
11:10:20 AM	Witness Excused (Baron)	
11:10:36 AM	Mike Kurtz (KIUC)	

11:11:13 AM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Mr. Fisk moves to enter SC Exhibits 28 through 36 into the record. No objections.
11:11:46 AM	Witness, Rachel Wilson (SC)	
	Note: Kathy Gillum	Witness called to testify by Shannon Fisk (SC).
11:12:04 AM	Shannon Fisk (SC)	
	Note: Kathy Gillum	Qualification of witness by Shannon Fisk. Modification to pre-filed testimony, page 5, line 22, should be 2014 to 2024. Witness adopts pre-filed testimony with the correction.
11:13:40 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Questions regarding Strategist Model pertaining to emissions.
11:15:08 AM	Witness Excused (Wilson)	
11:15:24 AM	Witness James R. Hornby (SC)	
	Note: Kathy Gillum	Witness called to testify by Kristin Henry (SC)
11:15:48 AM	Kristin Henry (SC)	
	Note: Kathy Gillum	Qualification of witness by Kristin Henry. Witness adopts pre-filed testimony and errata, with correction. Correction: removal of Dr. Fisher's testimony affected witness testimony pages 19-20 and his Exhibit 9.
11:17:58 AM	SC Exhibit 37	
	Note: Kathy Gillum	Exhibit: Redacted copy of Direct Testimony of J. Richard Hornby, dated May 1, 2012 Redacts document (as a withdrawal, not as confidential) Kristin Henry moves to admit Exhibit into record. No objections.
11:19:49 AM	Witness Excused (Hornby)	
11:20:15 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet requests to file Responses on May 11th,
11:20:47 AM	Faith Burns (PSC)	
	Note: Kathy Gillum	Ms. Burns states that the Briefs are due on May 9
11:21:20 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet stated that they were just trying to accomodate the Commission and compress the schedule. Discussion follows between the parties.
11:22:26 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz requests briefs be due May 11th.
11:23:09 AM	Mark Overstreet (Ky Power)	
	Note: Kathy Gillum	Mr. Overstreet states they would provide a rolling response to provide by the 9th.
11:23:27 AM	Dennis Howard (OAG)	
	Note: Kathy Gillum	Mr. Howard makes a suggestion regarding waiving time period.
11:23:56 AM	Vice Chair Gardner	
	Note: Kathy Gillum	Vice Chair Gardner states that the Commission is not comfortable with that suggestion.
11:24:49 AM	Mike Kurtz (KIUC)	
	Note: Kathy Gillum	Mr. Kurtz renews his request for the Briefs to be due by the 11th.
11:24:57 AM	Faith Burns (PSC)	
	Note: Kathy Gillum	Ms. Burns stated PSC had no objection to Briefs on the 11th. Commission granted.
11:25:08 AM	Case Recessed	
11:25:05 AM	Hearing Adjourned	
	Note: Kathy Gillum	Vice Chair Gardner adjourned the hearing.
1:47:03 PM	Case Stopped	

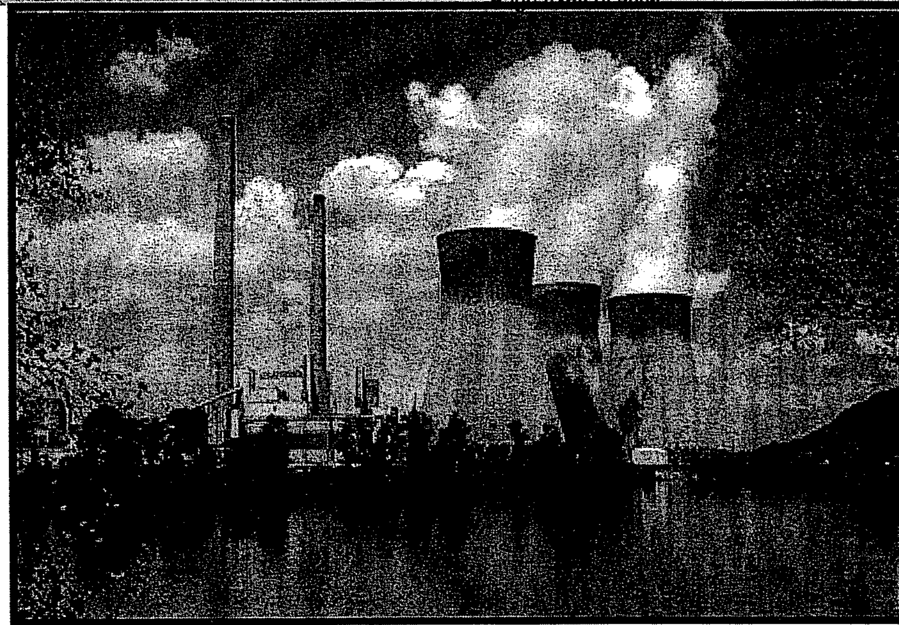
Exhibit List Report

Case Number: 2011-00401_02May12

Case Title: Kentucky Power Company (Environmental Surcharge)
Department:
Plaintiff:
Prosecution:
Defendant:
Defense:

Name	Description
SC Exhibit 28	Response to SC 1st DR dated January 13, 2012, Item 37
SC Exhibit 29	Response to SC 1st DR dated January 13, 2012, Item 69
SC Exhibit 30	Response to KIUC 1st DR dated January 13, 2012, Item 28,
SC Exhibit 31	Response to PSC 1st DR dated January 13, 2012, Item 48
SC Exhibit 32	Response to SC Supp DR dated Feb 8, 2012, Item 4
SC Exhibit 33	Responses to SC Supp. DR dated Feb 8, 2012, Item 34
SC Exhibit 34	Response to SC Supp DR dated Feb 8, 2012, Item 35,
SC Exhibit 35	Response to SC Supp DR dated Feb 8, 2012, Item 39
SC Exhibit 36	Copy of Ms. Wilson's notes regarding conversation with Mr. Becker
SC Exhibit 37	Redacted copy of Direct Testimony of J. Richard Hornby, dated May 1, 2012

AEP AMERICAN® ELECTRIC POWER



46th EEI Financial Conference Handout

Orlando, FL
November 7-8, 2011

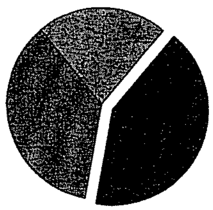
Insert to witness, Lane Kollen
Testimony handed out at hearing
(This is not an Exhibit)

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

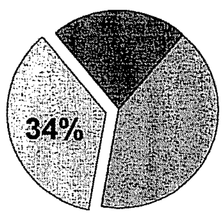
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

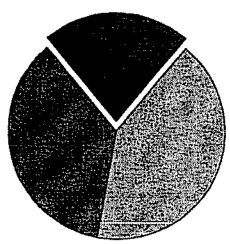
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078 (5)
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

(4) Includes NSR Compliance.

(5) Includes Big Sandy Unit 2, which remains fully exposed but, pending regulatory approval, will be scrubbed rather than replaced with new natural gas generation.

Retrofits/New Generation

AEP®

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
AEP Ohio	Conesville 5	400	SCR, DSI		
	Conesville 6	400	SCR, DSI		
	Muskingum River 5/6*	510	Refuel/ New Natural Gas		
	Gavin 1	1,320	FGD upgrade		
	Gavin 2	1,320	FGD upgrade		
	Zimmer 1	330	FGD upgrade		
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800** **
APCO	Clinch River 1***	211	Refuel with Natural Gas		
	Clinch River 2***	211	Refuel with Natural Gas		
	Dresden	580	New Natural Gas		
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765** ****
I&M	Rockport 1	1,310	FGD, SCR		
	Rockport 2	1,310	FGD, SCR		
	Tanners Creek 4	500	DSI, ACI		
	Total MW	**3,120**	**Total Expected Cost**	**1,240**	**1,670** *****
KPCO	Big Sandy 2	800	FGD		
	Total MW	**800**	**Total Expected Cost**		**525**

*Both options remain viable depending on outcome of ESP stipulation

**Assumes corporate separation in Ohio is approved and the investment is able to clear the market

***Retired Plant 235MW

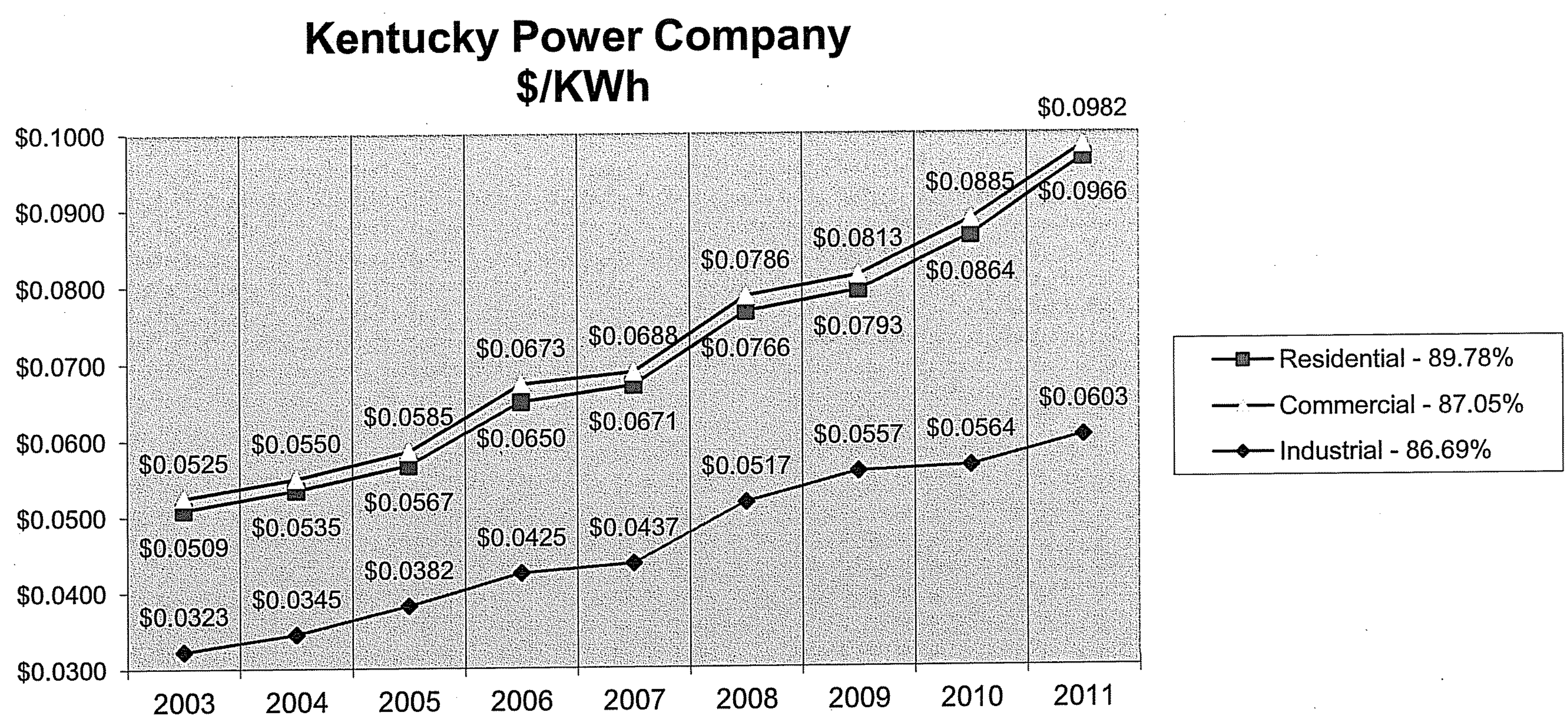
**** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

***** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	262	ACI, Baghouse		
	Total MW	**2,162**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Total MW	**278**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,109**	



Source Data: Kentucky Power FERC Form 1 (2003 - 2011)

KIUC EXHIBIT 1

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 2003

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,353,400	116,894,189	144,285	16,311	0.0497
3	Res Svc Load Mgmt TOD	5,953	224,594	200	29,765	0.0377
4	Residential Service TOD	19	834	1	19,000	0.0439
5	Small General Service	17	-962	1	17,000	-0.0566
6	Medium General Service	1	150			0.1500
7	All Outdoor Lighting	25,616	2,930,261			0.1144
8	Unbilled	-28,492	-48,221			0.0017
9	Total Residential	2,356,514	120,000,845	144,487	16,310	0.0509
10						
11	442 Commercial Sales					
12	Residential Service	8	437			0.0546
13	Small General Service	79,734	6,114,715	16,465	4,843	0.0767
14	Medium General Service	544,481	32,004,337	10,201	53,375	0.0588
15	Medium General Service TOD	1,637	87,570	55	29,764	0.0535
16	Large General Service	540,568	24,560,120	630	858,044	0.0454
17	Quantity Power	130,179	4,201,078	15	8,678,600	0.0323
18	Municipal Waterworks	8,437	370,006	23	366,826	0.0439
19	Street Lighting	55	4,974	1	55,000	0.0904
20	All Outdoor Lighting	13,019	1,270,144			0.0976
21	Unbilled	-6,176	291,325			-0.0472
22	Total Commercial	1,311,942	68,904,706	27,390	47,899	0.0525
23						
24	442 Industrial Sales					
25	Commercial & Industrial TOD	1,893,806	54,038,977	15	126,253,733	0.0285
26	Interruptible Power	1,932	202,633			0.1049
27	Small General Service	2,238	189,503	586	3,819	0.0847
28	Medium General Service	43,197	2,470,665	588	73,464	0.0572
29	Large General Service	262,767	11,809,447	210	1,251,271	0.0449
30	Quantity Power	730,283	25,533,752	64	11,410,672	0.0350
31	All Outdoor Lighting	836	73,994			0.0885
32	Unbilled	-4,850	247,804			-0.0511
33	Total Industrial	2,930,209	94,566,775	1,463	2,002,877	0.0323
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	6,649,408	283,950,022	173,788	38,262	0.0427
42	Total Unbilled Rev.(See Instr. 6)	-40,184	448,056	0	0	-0.0112
43	TOTAL	6,609,224	284,398,078	173,788	38,030	0.0430

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 2003

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street Lighting					
2	Small General Service	2,180	156,275	375	5,813	0.0717
3	Medium General Service	915	52,924	19	48,158	0.0578
4	Street Lighting	8,054	747,476	54	149,148	0.0928
5	All Outdoor Lighting	76	11,929			0.1570
6	Unbilled	-666	-42,852			0.0643
7	Total Public Street Lighting	10,559	925,752	448	23,569	0.0877
8						
9						
10						
11	Instruction 5. (See Note)					
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41	TOTAL Billed	6,649,408	283,950,022	173,788	38,262	0.0427
42	Total Unbilled Rev.(See Instr. 6)	-40,184	448,056	0	0	-0.0112
43	TOTAL	6,609,224	284,398,078	173,788	38,030	0.0430

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,376,987	124,017,665	144,236	16,480	0.0522
3	Res Svc Load Mgmt TOD	5,925	238,092	198	29,924	0.0402
4	Small General Service	6	290			0.0483
5	Medium General Service	8	495			0.0619
6	All Outdoor Lighting	26,013	3,087,193			0.1187
7	Unbilled	2,422	1,638,378			0.6765
8	Total Residential	2,411,361	128,982,113	144,434	16,695	0.0535
9						
10	442 Commercial Sales					
11	Small General Service	80,409	6,443,917	17,244	4,663	0.0801
12	Medium General Service	559,342	34,405,405	10,292	54,347	0.0615
13	Medium General Service TOD	1,970	106,470	70	28,143	0.0540
14	Large General Service	556,373	26,608,440	643	865,277	0.0478
15	Quantity Power	145,756	5,128,207	17	8,573,882	0.0352
16	Street Lighting	136	15,841	1	136,000	0.1165
17	Municipal Waterworks	7,498	352,591	22	340,818	0.0470
18	All Outdoor Lighting	13,513	1,374,282			0.1017
19	Unbilled	8,095	1,149,123			0.1420
20	Total Commercial	1,373,092	75,584,276	28,289	48,538	0.0550
21						
22	442 Industrial Sales					
23	Small General Service	2,137	191,865	587	3,641	0.0898
24	Medium General Service	42,778	2,550,459	591	72,382	0.0596
25	Large General Service	251,555	12,159,245	206	1,221,141	0.0483
26	Quantity Power	763,005	28,742,770	68	11,220,662	0.0377
27	Commerical & Industrial TOD	2,110,058	64,931,040	14	150,718,429	0.0308
28	All Outdoor Lighting	802	74,129			0.0924
29	Unbilled	10,662	1,117,046			0.1048
30	Total Industrial	3,180,997	109,766,554	1,466	2,169,848	0.0345
31						
32	444 Public Street Lighting					
33	Small General Service	1,845	145,810	368	5,014	0.0790
34	Medium General Service	1,037	61,794	21	49,381	0.0596
35	Street Lighting	8,169	785,916	53	154,132	0.0962
36	All Outdoor Lighting	79	13,286			0.1682
37	Unbilled	14	2,789			0.1992
38	Total Public Street Lighting	11,144	1,009,595	442	25,213	0.0906
39						
40	Instruction 5. (See Note)					
41	TOTAL Billed	6,955,401	311,435,202	174,631	39,829	0.0448
42	Total Unbilled Rev.(See Instr. 6)	21,193	3,907,336	0	0	0.1844
43	TOTAL	6,976,594	315,342,538	174,631	39,950	0.0452

Schedule Page: 304 Line No.: 6 Column: d

Per Instruction #3

Outdoor lighting customers served by more than one rate schedule:

Residential	40,130
Commercial	6,810
Industrial	294
Public Street & Highway	33
Total	47,267

Schedule Page: 304 Line No.: 18 Column: d

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		Fuel Clause
440 Residential		
	Residential Service	1,563,210
	Res Svc Load Mgmt TOD	3,023
	Small General Service	(9)
	Medium General Service	(9)
	All Outdoor Lighting	24,780
	Unbilled	1,598,993
Total		3,189,988
442 Commercial		
	Small General Service	55,798
	Medium General Service	439,383
	Medium General Service TOD	1,310
	Large General Service	469,192
	Quantity Power	135,687
	Street Lighting	82
	Municipal Waterworks	5,755
	All Outdoor Lighting	13,295
	Unbilled	805,464
Total		1,925,966
442 Industrial		
	Small General Service	1,433
	Medium General Service	28,724
	Large General Service	200,194
	Quantity Power	675,318
	Commercial & Industrial TOD	2,043,079
	All Outdoor Lighting	754
	Unbilled	707,276
Total		3,656,778
444 Public Street Lighting		
	Small General Service	1,463
	Medium General Service	1,044
	Street Lighting	7,897
	All Outdoor Lighting	77
	Unbilled	2,076
Total		12,557

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2005/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,479,126	138,961,087	144,314	17,179	0.0561
3	Res Svc Load Mgmt TOD	5,997	267,886	199	30,136	0.0447
4	Small General Service	13	726			0.0558
5	All Outdoor Lighting	26,525	3,230,207			0.1218
6	Unbilled	22,066	1,145,874			0.0519
7	Total Residential	2,533,727	143,605,780	144,513	17,533	0.0567
8						
9	442 Commercial Sales					
10	Residential Service	3	202			0.0673
11	Small General Service	73,060	6,386,999	17,283	4,227	0.0874
12	Medium General Service	590,082	38,592,014	10,817	54,551	0.0654
13	Medium General Service TOD	2,155	129,931	75	28,733	0.0603
14	Large General Service	574,485	29,806,915	650	883,823	0.0519
15	Quantity Power	160,519	6,454,209	19	8,448,368	0.0402
16	Street Lighting	53	6,202	1	53,000	0.1170
17	Municipal Waterworks	7,179	369,769	21	341,857	0.0515
18	All Outdoor Lighting	13,962	1,469,009			0.1052
19	Unbilled	1,138	45,935			0.0404
20	Total Commercial	1,422,636	83,261,185	28,866	49,284	0.0585
21						
22	442 Industrial Sales					
23	Small General Service	1,855	182,343	570	3,254	0.0983
24	Medium General Service	42,201	2,701,938	595	70,926	0.0640
25	Large General Service	249,708	13,509,744	209	1,194,775	0.0541
26	Quantity Power	818,127	33,900,426	68	12,031,279	0.0414
27	Commerical & Industrial TOD	2,231,725	77,393,386	15	148,781,667	0.0347
28	All Outdoor Lighting	816	78,576			0.0963
29	Unbilled	-1,813	-90,245			0.0498
30	Total Industrial	3,342,619	127,676,168	1,457	2,294,179	0.0382
31						
32	444 Public Street Lighting					
33	Small General Service	865	94,760	341	2,537	0.1095
34	Medium General Service	1,055	67,075	23	45,870	0.0636
35	Street Lighting	8,135	812,120	55	147,909	0.0998
36	All Outdoor Lighting	91	14,579			0.1602
37	Unbilled	-112	-7,148			0.0638
38	Total Public Street Lighting	10,034	981,386	419	23,947	0.0978
39						
40	Instruction 5. (See Note)					
41	TOTAL Billed	7,287,737	354,430,103	175,255	41,584	0.0486
42	Total Unbilled Rev.(See Instr. 6)	21,279	1,094,416	0	0	0.0514
43	TOTAL	7,309,016	355,524,519	175,255	41,705	0.0486

Schedule Page: 304 Line No.: 6 Column: d

Per Instruction #3

Outdoor lighting customers served by more than one rate schedule:

Residential	40,725
Commercial	6,939
Industrial	282
Public Street & Highway	32
Total	47,978

Schedule Page: 304 Line No.: 18 Column: d

Schedule Page: 304 Line No.: 28 Column: d

Schedule Page: 304 Line No.: 36 Column: d

Schedule Page: 304 Line No.: 40 Column: a

440 Residential	Fuel Clause
Residential Service	8,438,915
Res Svc Load Mgmt TOD	20,512
Small General Service	81
All Outdoor Lighting	92,013
Unbilled	(678,656)
Total	7,872,865

442 Commercial	
Residential Service	7
Small General Service	250,720
Medium General Service	1,989,405
Medium General Service TOD	7,328
Large General Service	1,949,775
Quantity Power	543,916
Street Lighting	224
Municipal Waterworks	24,539
All Outdoor Lighting	48,485
Unbilled	(378,305)
Total	4,436,094

442 Industrial	
Small General Service	6,424
Medium General Service	144,491
Large General Service	866,859
Quantity Power	2,811,927
Commercial & Industrial TOD	7,054,608
All Outdoor Lighting	2,825
Unbilled	(346,065)
Total	10,541,069

FOOTNOTE DATA

444 Public Street Lighting

Small General Service	3,153
Medium General Service	3,670
Street Lighting	28,843
All Outdoor Lighting	311
Unbilled	(1,350)
Total	34,627

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2006/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,398,884	152,024,371	144,247	16,630	0.0634
3	Res Svc Load Mgmt TOD	5,696	296,504	200	28,480	0.0521
4	Small General Service	1	153			0.1530
5	All Outdoor Lighting	27,046	3,772,359			0.1395
6	Unbilled	-22,390	453,620			-0.0203
7	Total Residential	2,409,237	156,547,007	144,447	16,679	0.0650
8						
9	442 Commercial Sales					
10	Residential Service	2	160			0.0800
11	Small General Service	103,038	9,587,264	19,946	5,166	0.0930
12	Medium General Service	537,820	39,560,964	8,558	62,844	0.0736
13	Medium General Service TOD	2,140	143,686	74	28,919	0.0671
14	Large General Service	567,063	34,273,859	666	851,446	0.0604
15	Quantity Power	168,487	7,640,851	19	8,867,737	0.0453
16	Municipal Waterworks	7,014	411,175	20	350,700	0.0586
17	All Outdoor Lighting	14,274	1,628,925			0.1141
18	Unbilled	-7,605	411,741			-0.0541
19	Total Commercial	1,392,233	93,658,625	29,283	47,544	0.0673
20						
21	442 Industrial Sales					
22	Small General Services	3,711	347,821	728	5,098	0.0937
23	Medium General Services	36,793	2,673,080	444	82,867	0.0727
24	Large General Services	218,021	13,554,767	202	1,079,312	0.0622
25	Quantity Power	778,676	35,427,158	70	11,123,943	0.0455
26	Commercial & Industrial TOD	2,273,526	88,176,189	17	133,736,824	0.0388
27	All Outdoor Lighting	872	89,978			0.1032
28	Unbilled	-419	358,114			-0.8547
29	Total Industrial Sales	3,311,180	140,627,107	1,461	2,266,379	0.0425
30						
31	444 Public Street Lighting					
32	Small General Service	591	86,063	310	1,906	0.1456
33	Medium General Service	900	63,454	15	60,000	0.0705
34	Street Lighting	8,231	935,410	55	149,655	0.1136
35	All Outdoor Lighting	95	15,882			0.1672
36	Unbilled	-8	872			-0.1090
37	Total Public Street Lighting	9,809	1,101,681	380	25,813	0.1123
38						
39						
40	Instruction 5. (See Footnote)					
41	TOTAL Billed	7,152,881	390,710,073	175,571	40,741	0.0546
42	Total Unbilled Rev.(See Instr. 6)	-30,422	1,224,347	0	0	-0.0402
43	TOTAL	7,122,459	391,934,420	175,571	40,567	0.0550

Schedule Page: 304 Line No.: 5 Column: d

Per Instruction #3

Outdoor Lighting customers served by more than one rate schedule:

Residential	41,297
Commercial	7,025
Industrial	283
Public Street & Highway	33
Total	48,638

Schedule Page: 304 Line No.: 17 Column: d

Schedule Page: 304 Line No.: 27 Column: d

Schedule Page: 304 Line No.: 35 Column: d

Schedule Page: 304 Line No.: 40 Column: a

440 Residential		Fuel Clause
	Residential Service	4,336,521
	Res Svc Load Mgmt TOD	10,556
	Small General Service	2
	All Outdoor Lighting	42,766
	Unbilled	(255,434)
Total		4,134,411
442 Commercial		
	Residential Service	5
	Small General Service	176,859
	Medium General Service	962,192
	Medium General Service TOD	4,045
	Large General Service	979,081
	Quantity Power	293,678
	Municipal Waterworks	12,457
	All Outdoor Lighting	22,587
	Unbilled	(111,570)
Total		2,339,334
442 Industrial		
	Small General Service	6,829
	Medium General Service	64,757
	Large General Service	376,078
	Quantity Power	1,397,945
	Commercial & Industrial TOD	3,889,574
	All Outdoor Lighting	1,350
	Unbilled	(76,670)
Total		5,659,863

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	/ /	2006/Q4

FOOTNOTE DATA

444 Public Street Lighting	
Small General Service	1,012
Medium General Service	1,640
Street Lighting	13,053
All Outdoor Lighting	152
Unbilled	(148)
Total	15,709

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,474,422	164,274,744	144,010	17,182	0.0664
3	Res Service Load Management	5,658	312,284	196	28,867	0.0552
4	Residential Service TOD	61	4,004	1	61,000	0.0656
5	Small General Service	6	535			0.0892
6	Medium General Service	2	167			0.0835
7	All Outdoor Lighting	27,208	3,980,159			0.1463
8	Enviromental Surcharge		-79,019			
9	Subtotal Billed	2,507,357	168,492,874	144,207	17,387	0.0672
10	Unbilled Revenue	-22,792	-1,674,588			0.0735
11	Total Residential	2,484,565	166,818,286	144,207	17,229	0.0671
12						
13	442 Commercial Sales					
14	Residential Service	3	197			0.0657
15	Small General Service	125,611	11,518,592	21,317	5,893	0.0917
16	Medium General Service	537,259	40,892,172	7,579	70,888	0.0761
17	Medium General Service TOD	2,318	161,648	75	30,907	0.0697
18	Large General Service	590,871	37,302,569	677	872,778	0.0631
19	Quantity Power	174,425	8,084,847	19	9,180,263	0.0464
20	Municipal Waterworks	7,303	446,221	20	365,150	0.0611
21	All Outdoor Lighting	14,684	1,716,589			0.1169
22	Enviromental Surcharge		-58,261			
23	Estimated Revenue	-74	-4,230			0.0572
24	Subtotal Billed	1,452,400	100,060,344	29,687	48,924	0.0689
25	Unbilled Revenue	-6,591	-588,932			0.0894
26	Total Commercial	1,445,809	99,471,412	29,687	48,702	0.0688
27						
28	442 Industrial Sales					
29	Small General Service	4,792	430,409	780	6,144	0.0898
30	Medium General Service	36,992	2,757,420	381	97,092	0.0745
31	Large General Service	203,798	13,086,215	188	1,084,032	0.0642
32	Quantity Power	755,771	35,740,840	71	10,644,662	0.0473
33	Commercial & Industrial TOD	2,078,045	83,360,301	16	129,877,813	0.0401
34	All Outdoor Lighting	994	105,495			0.1061
35	Enviromental Surcharge		-57,066			
36	Estimated Revenue	101,292	3,650,138			0.0360
37	Subtotal Billed	3,181,684	139,073,752	1,436	2,215,657	0.0437
38	Unbilled Revenue	-7,637	-422,886			0.0554
39	Total Industrial	3,174,047	138,650,866	1,436	2,210,339	0.0437
40						
41	TOTAL Billed	7,151,457	408,783,539	175,705	40,701	0.0572
42	Total Unbilled Rev.(See Instr. 6)	-36,951	-2,680,876	0	0	0.0726
43	TOTAL	7,114,506	406,102,663	175,705	40,491	0.0571

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street Lighting					
2	Small General Service	709	96,631	307	2,309	0.1363
3	Medium General Service	964	70,892	13	74,154	0.0735
4	Street Lighting	8,247	973,444	55	149,945	0.1180
5	All Outdoor Lighting	96	16,335			0.1702
6	Enviromental Surcharge		-733			
7	Subtotal Billed	10,016	1,156,569	375	26,709	0.1155
8	Unbilled Revenue	69	5,530			0.0801
9	Total Public Street Lighting	10,085	1,162,099	375	26,893	0.1152
10						
11	Instruction 5. (See Footnote)					
12						
13						
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38						
39						
40						
41	TOTAL Billed	7,151,457	408,783,539	175,705	40,701	0.0572
42	Total Unbilled Rev.(See Instr. 6)	-36,951	-2,680,876	0	0	0.0726
43	TOTAL	7,114,506	406,102,663	175,705	40,491	0.0571

Name of Respondent	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company		/ /	2007/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 7 Column: d

Per Instruction #3

Outdoor Lighting customers served by more than one rate schedule:

Residential	41,292
Commercial	7,101
Industrial	280
Public Street & Highway	34
Total	48,707

Schedule Page: 304 Line No.: 21 Column: d

Schedule Page: 304 Line No.: 34 Column: d

Schedule Page: 304.1 Line No.: 5 Column: d

Schedule Page: 304.1 Line No.: 11 Column: a

440 Residential		Fuel Clause
	Residential Service	3,652,713
	Res Service Load Management	8,695
	Residential Service TOD	76
	Small General Service	12
	Medium General Service	(1)
	All Outdoor Lighting	34,101
	Unbilled	(980,170)
Total		2,715,426
442 Commercial		
	Enviromental Surcharge	-
	Small General Service	179,511
	Medium General Service	764,439
	Medium General Service TOD	3,413
	Large General Service	803,644
	Quantity Power	241,280
	Municipal Waterworks	10,431
	All Outdoor Lighting	18,230
	Estimated	(145)
	Unbilled	(479,993)
Total		1,540,810
442 Industrial		
	Small General Service	6,823
	Medium General Service	52,519
	Large General Service	278,075
	Quantity Power	1,052,651
	Commercial & Industrial TOD	3,101,872
	All Outdoor Lighting	1,224
	Estimated	197,291
	Unbilled	(407,281)
Total		4,283,174

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) __ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

444 Public Street Lighting	
Small General Service	957
Medium General Service	1,273
Street Lighting	10,342
All Outdoor Lighting	119
Unbilled	(936)
Total	11,755

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,461,328	183,691,832	143,995	17,093	0.0746
3	Res Service Load Management	3,450	205,464	109	31,651	0.0596
4	Residential Service TOD	70	5,126	1	70,000	0.0732
5	Small General Service					
6	Medium General Service					
7	All Outdoor Lighting	27,342	4,273,338			0.1563
8	Mark West HC					
9	Metering Adjustment		79,019			
10	Subtotal Billed	2,492,190	188,254,779	144,105	17,294	0.0755
11	Unbilled Revenue	-11,021	1,678,846			-0.1523
12	Total Residential	2,481,169	189,933,625	144,105	17,218	0.0766
13						
14	442 Commercial Sales					
15	Residential Service		36			
16	Small General Service	128,544	12,913,142	21,436	5,997	0.1005
17	Medium General Service	519,847	44,167,984	7,478	69,517	0.0850
18	Medium General Service TOD	2,346	180,730	75	31,280	0.0770
19	Large General Service	591,731	42,751,042	700	845,330	0.0722
20	Quantity Power	177,028	9,653,289	20	8,851,400	0.0545
21	Municipal Waterworks					
22	All Outdoor Lighting	15,038	1,904,877			0.1267
23	Mark West HC	7,840	545,004	20	392,000	0.0695
24	Estimated Revenue	72	5,586	1	72,000	0.0776
25	Metering Adjustment		58,261			
26	Subtotal Billed	1,442,446	112,179,951	29,730	48,518	0.0778
27	Unbilled Revenue	-13,704	159,843			-0.0117
28	Total Commercial	1,428,742	112,339,794	29,730	48,057	0.0786
29						
30	442 Industrial Sales					
31	Small General Service	5,278	508,423	791	6,673	0.0963
32	Medium General Service	37,482	3,089,269	362	103,541	0.0824
33	Large General Service	198,444	14,649,192	197	1,007,330	0.0738
34	Quantity Power	797,143	44,013,236	66	12,077,924	0.0552
35	Commercial & Industrial TOD	2,290,486	107,597,445	16	143,155,375	0.0470
36	All Outdoor Lighting	988	114,405			0.1158
37	Mark West HC					
38	Estimated Revenue	-4,564	1,873,941			-0.4106
39	Metering Adjustment		57,066			
40	Subtotal Billed	3,325,257	171,902,977	1,432	2,322,107	0.0517
41	TOTAL Billed	7,270,188	473,622,695	175,646	41,391	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-28,286	2,612,932	0	0	-0.0924
43	TOTAL	7,241,902	476,235,627	175,646	41,230	0.0658

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Unbilled Revenue	-3,497	777,811			-0.2224
2	Total Industrial	3,321,760	172,680,788	1,432	2,319,665	0.0520
3						
4	444 Public Street Lighting					
5	Small General Service	756	107,262	310	2,439	0.1419
6	Medium General Service	923	75,263	12	76,917	0.0815
7	Street Lighting	8,517	1,084,036	57	149,421	0.1273
8	All Outdoor Lighting	99	17,695			0.1787
9	Mark West HC					
10	Metering Adjustment		732			
11	Subtotal Billed	10,295	1,284,988	379	27,164	0.1248
12	Unbilled Revenue	-64	-3,568			0.0558
13	Total Public Street Lighting	10,231	1,281,420	379	26,995	0.1252
14						
15	Instruction 5. (See Footnote)					
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41	TOTAL Billed	7,270,188	473,622,695	175,646	41,391	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-28,286	2,612,932	0	0	-0.0924
43	TOTAL	7,241,902	476,235,627	175,646	41,230	0.0658

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	/ /	2008/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 7 Column: d

Per Instruction #3

Outdoor Lighting customers served by more than one rate schedule:

Residential	41,347
Commercial	7,224
Industrial	273
Public Street & Highway	35
Total	48,879

Schedule Page: 304 Line No.: 22 Column: d

Schedule Page: 304 Line No.: 36 Column: d

Schedule Page: 304.1 Line No.: 8 Column: d

Schedule Page: 304.1 Line No.: 15 Column: a

440 Residential		Fuel Clause
	Residential Service	10,805,466
	Res Service Load Management	14,135
	Residential Service TOD	336
	All Outdoor Lighting	140,253
	Unbilled	2,487,796
Total		13,447,986
442 Commercial		
	Residential Service	4
	Mark West HC	35,178
	Small General Service	586,286
	Medium General Service	2,428,357
	Medium General Service TOD	10,761
	Large General Service	2,794,029
	Quantity Power	860,779
	All Outdoor Lighting	77,340
	Estimated	1,215
	Unbilled	1,143,762
Total		7,937,711
442 Industrial		
	Small General Service	25,855
	Medium General Service	159,903
	Large General Service	937,254
	Quantity Power	3,838,296
	Commercial & Industrial TOD	9,439,623
	All Outdoor Lighting	5,117
	Estimated	1,533,205
	Unbilled	1,059,339
Total		16,998,592
444 Public Street Lighting		
	Small General Service	3,645

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,397,984	189,410,883	143,519	16,708	0.0790
3	Res Service Load Management	3,262	211,028	108	30,204	0.0647
4	Residential Service TOD	41	3,185	1	41,000	0.0777
5	Small General Service	2	155			0.0775
6	Medium General Service	9	874			0.0971
7	All Outdoor Lighting	27,255	4,356,200			0.1598
8	Mark West HC					
9	Metering Adjustment					
10	Subtotal Billed	2,428,553	193,982,325	143,628	16,909	0.0799
11	Unbilled Revenue	-2,941	-1,719,801			0.5848
12	Total Residential	2,425,612	192,262,524	143,628	16,888	0.0793
13						
14	442 Commercial Sales					
15	Residential Service	2	352			0.1760
16	Small General Service	129,873	13,649,694	21,440	6,058	0.1051
17	Medium General Service	516,939	46,018,911	7,319	70,630	0.0890
18	Medium General Service TOD	3,483	277,368	80	43,538	0.0796
19	Large General Service	569,693	43,476,743	676	842,741	0.0763
20	Quantity Power	174,489	10,038,489	19	9,183,632	0.0575
21	Municipal Waterworks					
22	All Outdoor Lighting	15,025	1,952,006			0.1299
23	Mark West HC	7,926	583,925	20	396,300	0.0737
24	Estimated Revenue	196	12,417	1	196,000	0.0634
25	Metering Adjustment					
26	Subtotal Billed	1,417,626	116,009,905	29,555	47,966	0.0818
27	Unbilled Revenue	8,638	-43,632			-0.0051
28	Total Commercial	1,426,264	115,966,273	29,555	48,258	0.0813
29						
30	442 Industrial Sales					
31	Small General Service	5,612	555,409	813	6,903	0.0990
32	Medium General Service	34,902	3,028,437	353	98,873	0.0868
33	Large General Service	175,182	13,662,594	185	946,930	0.0780
34	Quantity Power	723,877	44,581,628	68	10,645,250	0.0616
35	Commercial & Industrial TOD	2,348,613	121,981,569	18	130,478,500	0.0519
36	All Outdoor Lighting	1,015	120,392			0.1186
37	Mark West HC					
38	Estimated Revenue	-89,335	-5,153,254	1	-89,335,000	0.0577
39	Metering Adjustment					
40	Subtotal Billed	3,199,866	178,776,775	1,438	2,225,220	0.0559
41	TOTAL Billed	7,056,283	490,083,641	174,994	40,323	0.0695
42	Total Unbilled Rev.(See Instr. 6)	12,173	-2,086,051	0	0	-0.1714
43	TOTAL	7,068,456	487,997,590	174,994	40,393	0.0690

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Unbilled Revenue	6,446	-324,068			-0.0503
2	Total Industrial	3,206,312	178,452,707	1,438	2,229,702	0.0557
3						
4	444 Public Street Lighting					
5	Small General Service	787	112,061	307	2,564	0.1424
6	Medium General Service	853	72,955	10	85,300	0.0855
7	Street Lighting	8,497	1,111,269	56	151,732	0.1308
8	All Outdoor Lighting	101	18,351			0.1817
9	Mark West HC					
10	Metering Adjustment					
11	Subtotal Billed	10,238	1,314,636	373	27,448	0.1284
12	Unbilled Revenue	30	1,450			0.0483
13	Total Public Street Lighting	10,268	1,316,086	373	27,528	0.1282
14						
15	Instruction 5. (See Footnote)					
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41	TOTAL Billed	7,056,283	490,083,641	174,994	40,323	0.0695
42	Total Unbilled Rev.(See Instr. 6)	12,173	-2,086,051	0	0	-0.1714
43	TOTAL	7,068,456	487,997,590	174,994	40,393	0.0690

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	/ /	2009/Q4

FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 15 Column: a

FUEL CLAUSE

440 Residential	
Residential Service	11,842,244
Res Service Load Management	16,569
Residential Service TOD	353
Small General Service	11
Medium General Service	96
All Outdoor Lighting	106,227
Unbilled	(2,612,728)
Total Residential	9,352,772
442 Commercial	
Residential Service	(12)
Mark West HC	37,090
Small General Service	631,146
Medium General Service	2,473,795
Medium General Service TOD	13,318
Large General Service	2,642,566
Quantity Power	795,549
All Outdoor Lighting	58,775
Estimated	(2,666)
Unbilled	(1,214,893)
Total Commercial	5,434,668
442 Industrial	
Small General Service	27,447
Medium General Service	159,964
Large General Service	817,668
Quantity Power	3,392,799
Commercial & Industrial TOD	11,957,901
All Outdoor Lighting	3,974
Estimated	(1,819,740)
Unbilled	(1,150,749)
Total Industrial	13,389,264
444 Public Street Lighting	
Small General Service	3,638
Medium General Service	3,677
Street Lighting	32,754
All Outdoor Lighting	391
Unbilled	(2,377)
Total Public Street Light	38,083
TOTAL FUEL CLAUSE	28,214,787

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,551,546	214,587,698	142,864	17,860	0.0841
3	Res Service Load Management	3,217	224,968	103	31,233	0.0699
4	Residential Service TOD	6	598	1	6,000	0.0997
5	Small General Service	66	5,157	3	22,000	0.0781
6	Medium General Service		5			
7	All Outdoor Lighting	27,191	4,769,228			0.1754
8	Subtotal Billed	2,582,026	219,587,654	142,971	18,060	0.0850
9	Unbilled Revenue	31,484	6,349,960			0.2017
10	Total Residential	2,613,510	225,937,614	142,971	18,280	0.0864
11						
12	442 Commercial Sales					
13	Residential Service	2	131			0.0655
14	Small General Service	138,515	15,408,978	21,807	6,352	0.1112
15	Medium General Service	532,181	50,521,127	7,182	74,099	0.0949
16	Medium General Service TOD	4,461	374,067	83	53,747	0.0839
17	Large General Service	585,773	47,884,878	682	858,905	0.0817
18	Quantity Power	176,100	10,349,441	20	8,805,000	0.0588
19	All Outdoor Lighting	15,115	2,113,936			0.1399
20	Mark West HC	6,501	495,567	16	406,313	0.0762
21	Estimated Revenue	274	20,634	1	274,000	0.0753
22	Subtotal Billed	1,458,922	127,168,759	29,791	48,972	0.0872
23	Unbilled Revenue	10,038	2,777,654			0.2767
24	Total Commercial	1,468,960	129,946,413	29,791	49,309	0.0885
25						
26	442 Industrial Sales					
27	Small General Service	5,806	608,444	812	7,150	0.1048
28	Medium General Service	33,591	3,128,353	359	93,568	0.0931
29	Large General Service	178,564	14,224,181	169	1,056,592	0.0797
30	Quantity Power	666,517	42,152,431	67	9,948,015	0.0632
31	Commercial & Industrial TOD	2,262,704	117,047,855	18	125,705,778	0.0517
32	All Outdoor Lighting	987	125,009			0.1267
33	Estimated Revenue	103,616	5,263,806	1	103,616,000	0.0508
34	Subtotal Billed	3,251,785	182,550,079	1,426	2,280,354	0.0561
35	Unbilled Revenue	3,946	1,193,059			0.3023
36	Total Industrial	3,255,731	183,743,138	1,426	2,283,121	0.0564
37						
38						
39						
40						
41	TOTAL Billed	7,303,047	530,751,898	174,579	41,832	0.0727
42	Total Unbilled Rev.(See Instr. 6)	45,482	10,327,568	0	0	0.2271
43	TOTAL	7,348,529	541,079,466	174,579	42,093	0.0736

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street Lighting					
2	Small General Service	796	122,182	324	2,457	0.1535
3	Medium General Service	914	84,176	11	83,091	0.0921
4	Street Lighting	8,501	1,218,562	56	151,804	0.1433
5	All Outdoor Lighting	103	20,486			0.1989
6	Subtotal Billed	10,314	1,445,406	391	26,379	0.1401
7	Unbilled Revenue	14	6,895			0.4925
8	Total Public Street Lighting	10,328	1,452,301	391	26,414	0.1406
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10	Instruction 5. (See Footnote)					
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41	TOTAL Billed	7,303,047	530,751,898	174,579	41,832	0.0727
42	Total Unbilled Rev.(See Instr. 6)	45,482	10,327,568	0	0	0.2271
43	TOTAL	7,348,529	541,079,466	174,579	42,093	0.0736

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FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 10 Column: a

FUEL CLAUSE

440 Residential	
Residential Service	(4,252,335)
Res Service Load Management	(5,275)
Residential Service TOD	(10)
Small General Service	166
All Outdoor Lighting	(49,955)
Unbilled	615,704
Total Residential	(3,691,705)
442 Commercial	
Residential Service	(3)
Mark West HC	(10,399)
Small General Service	(241,385)
Medium General Service	(932,461)
Medium General Service TOD	(7,656)
Large General Service	(1,048,895)
Quantity Power	(322,971)
All Outdoor Lighting	(27,587)
Estimated	1,274
Unbilled	318,177
Total Commercial	(2,271,906)
442 Industrial	
Small General Service	(10,036)
Medium General Service	(58,674)
Large General Service	(314,049)
Quantity Power	(1,115,688)
Commercial & Industrial TOD	(4,294,509)
All Outdoor Lighting	(1,795)
Estimated	37,696
Unbilled	297,717
Total Industrial	(5,459,338)
444 Public Street Lighting	
Small General Service	(1,067)
Medium General Service	(1,438)
Street Lighting	(16,119)
All Outdoor Lighting	(189)
Unbilled	665
Total Public Street Light	(18,148)
TOTAL FUEL CLAUSE	(11,441,097)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	2,379,122	226,939,820	141,755	16,783	0.0954
3	Res Service Load Management	2,923	240,693	101	28,941	0.0823
4	Residential Service TOD	25	2,453	2	12,500	0.0981
5	Small General Service	15	1,544	2	7,500	0.1029
6	All Outdoor Lighting	26,895	5,241,141			0.1949
7	Subtotal Billed	2,408,980	232,425,651	141,860	16,981	0.0965
8	Unbilled Revenue	-66,959	-6,256,273			0.0934
9	Total Residential	2,342,021	226,169,378	141,860	16,509	0.0966
10						
11	442 Commercial Sales					
12	Small General Service	134,286	16,927,686	22,067	6,085	0.1261
13	Medium General Service	498,145	53,270,712	7,070	70,459	0.1069
14	Medium General Service TOD	4,366	414,823	80	54,575	0.0950
15	Large General Service	576,975	53,573,804	714	808,088	0.0929
16	Quantity Power	169,956	10,879,704	20	8,497,800	0.0640
17	All Outdoor Lighting	15,177	2,330,301			0.1535
18	Mark West HC	5,026	438,725	13	386,615	0.0873
19	Estimated Revenue	2,764	227,680			0.0824
20	Subtotal Billed	1,406,695	138,063,435	29,964	46,946	0.0981
21	Unbilled Revenue	-25,988	-2,546,029			0.0980
22	Total Commercial	1,380,707	135,517,406	29,964	46,079	0.0982
23						
24	442 Industrial Sales					
25	Small General Service	5,453	649,806	794	6,868	0.1192
26	Medium General Service	29,435	3,131,854	350	84,100	0.1064
27	Large General Service	176,066	15,762,936	178	989,135	0.0895
28	Quantity Power	690,700	47,770,954	67	10,308,955	0.0692
29	Commercial & Industrial TOD	2,477,386	135,176,822	18	137,632,556	0.0546
30	All Outdoor Lighting	947	132,117			0.1395
31	Estimated Revenue	-117,663	-5,894,005	-1	117,663,000	0.0501
32	Subtotal Billed	3,262,324	196,730,484	1,406	2,320,287	0.0603
33	Unbilled Revenue	-12,433	-866,875			0.0697
34	Total Industrial	3,249,891	195,863,609	1,406	2,311,445	0.0603
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	7,088,589	568,845,163	173,641	40,823	0.0802
42	Total Unbilled Rev.(See Instr. 6)	-105,426	-9,676,073	0	0	0.0918
43	TOTAL	6,983,163	559,169,090	173,641	40,216	0.0801

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street Lighting					
2	Small General Service	746	132,519	343	2,175	0.1776
3	Medium General Service	1,202	123,674	12	100,167	0.1029
4	Street Lighting	8,539	1,346,662	56	152,482	0.1577
5	All Outdoor Lighting	103	22,738			0.2208
6	Subtotal Billed	10,590	1,625,593	411	25,766	0.1535
7	Unbilled Revenue	-46	-6,896			0.1499
8	Total Public Street Lighting	10,544	1,618,697	411	25,655	0.1535
9						
10	Instruction 5. (See Footnote)					
11						
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41	TOTAL Billed	7,088,589	568,845,163	173,641	40,823	0.0802
42	Total Unbilled Rev.(See Instr. 6)	-105,426	-9,676,073	0	0	0.0918
43	TOTAL	6,983,163	559,169,090	173,641	40,216	0.0801

Schedule Page: 304.1 Line No.: 10 Column: a

FUEL CLAUSE

440 Residential	
Residential Service	1,211,175
Res Service Load Management	1,407
Residential Service TOD	29
All Outdoor Lighting	16,732
Unbilled	269,071
Total Residential	1,498,414
442 Commercial	
Mark West HC	2,586
Small General Service	71,490
Medium General Service	259,795
Medium General Service TOD	2,338
Large General Service	311,110
Quantity Power	85,461
All Outdoor Lighting	9,530
Estimated	10,527
Unbilled	140,677
Total Commercial	893,514
442 Industrial	
Small General Service	2,900
Medium General Service	14,441
Large General Service	86,409
Quantity Power	371,103
Commercial & Industrial TOD	1,227,695
All Outdoor Lighting	561
Estimated	38,358
Unbilled	141,124
Total Industrial	1,882,591
444 Public Street Lighting	
Small General Service	408
Medium General Service	705
Street Lighting	5,539
All Outdoor Lighting	64
Unbilled	293
Total Public Street Light	7,009
TOTAL FUEL CLAUSE	4,281,528

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, lines 18-19. Provide the source and calculations supporting the $75 per ton coal cost and the approximately $165 million per year injected into the local economy.

RESPONSE

The $75 per ton coal cost was an estimated average cost per ton of coal as was the 2.2 million tons of coal consumed to calculate the $165 million dollars per year. The Company did not break down the consumption by unit.

WITNESS: Ranie K Wohnhas

KIUC EXHIBIT 2

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, lines 20-21. It states, "...
with the indirect impact on mining and transportation (500 jobs, $8 million in severance taxes, and $25 million in wages per year) of the gas options."

a. Provide the calculations that support the 500 jobs, $8 million in severance taxes, and the $25 million in wages per year.

b. Explain whether Kentucky Power anticipates that all coal burned at Big Sandy Unit 2 after the dry FGD is installed will come from Kentucky sources.

RESPONSE

a. This information was provided by the "Committee to Save the Big Sandy Power Plant" which was sponsored by Energy Ventures Analysis, Inc. Please refer to page 2 of this response for the supporting document.

b. Currently all coal burned at Big Sandy Unit 2 does not come from Kentucky sources and the Company anticpates that after the dry FGD is installed it will continue to burn coal at Big Sandy Unit 2 from both Kentucky and non-Kentucky sources.

WITNESS: Ranie K Wohnhas

COMMITTEE TO SAVE THE BIG SANDY POWER PLANT

1. AEP Kentucky Power serves the East Kentucky coal fields. Most of the economic activity and jobs in AEP's service territory are related to coal mining and support services. Over one-third of the entire industrial load of Kentucky Power is coal mines.
2. Kentucky Power owns only one power plant, the 1,060 MW Big Sandy plant, located in Louisa, Kentucky, which provides most of the power to this service territory. The Big Sandy plant burns about 2.5 million tons per year of coal, almost all mined in East Kentucky (a little comes from West Virginia). In 2010, this plant spent $175 million on coal purchases.
3. New EPA regulations proposed in 2011 (Utility MACT and Cross-State Air Pollution Rule) will require AEP to invest in new emission controls (scrubbers) in order to keep burning coal at Big Sandy, or close the plant.
4. AEP has not yet decided whether to invest in keeping the Big Sandy plant open. Originally, AEP planned to build scrubbers at Big Sandy, but recently AEP has announced that the plant may be closed and replaced with a new natural gas plant, because of EPA's new regulations.
5. Whether AEP invests in Big Sandy or closes it and replaces it with gas, the ratepayers of Kentucky Power will be faced with a large rate increase to pay for compliance with the new EPA regulations. The coal mining community of East Kentucky believes that Kentucky Power should invest in the Big Sandy plant because the jobs and tax revenues from this plant support the entire area. .
6. The coal produced to supply Big Sandy provides the local area over 500 direct mining jobs, severance taxes over $8 million per year, and wages over $25 million per year. In addition, the coal burned by Big Sandy supports jobs for suppliers and truckers, as well as taxes for the local schools and governments.
7. National environmental groups are intervening in Kentucky's rate cases to try to force utilities to close power plants burning Kentucky coal. The local community, who are Kentucky Power's largest ratepayers, support investing in Big Sandy and burning Kentucky coal. We need the support of the elected representatives of East Kentucky to save the Big Sandy power plant.

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 10, lines 18 to 22.

a. Please confirm that if the Company used a 50/50 blend of either NAPP or ILB coals with CAPP coals at Big Sandy Unit 2 the Company would reduce the quantity of Kentucky coal it would purchase for Big Sandy Unit 2 by 50 percent. If Mr. Wohnhas cannot confirm this, please explain why not.

b. Is it the Company's position that if the Company reduces the quantity of Kentucky coal it purchases for Big Sandy Unit 2 by 50 percent it would reduce the direct and indirect economic impact of sales of Kentucky coal to the Big Sandy plant presented by Mr. Wohnhas on page 8, lines 19 to 21, by 50 percent. If no, please explain why not.

RESPONSE

a. Use of a 50/50 blend of either NAPP or ILB coals with CAPP coal would not necessarily reduce the quantity of Kentucky coal that KPCo purchases by 50 percent. In 2011 KPCo purchased roughly 30% of its total coal (CAPP) from sources within Kentucky, with the balance coming from West Virginia. If KPCo moves to a blend of 50/50 NAPP or ILB and CAPP coal, the percentage of CAPP coal from Kentucky could increase or decrease depending on future prices offered to the Company by sources within Kentucky.

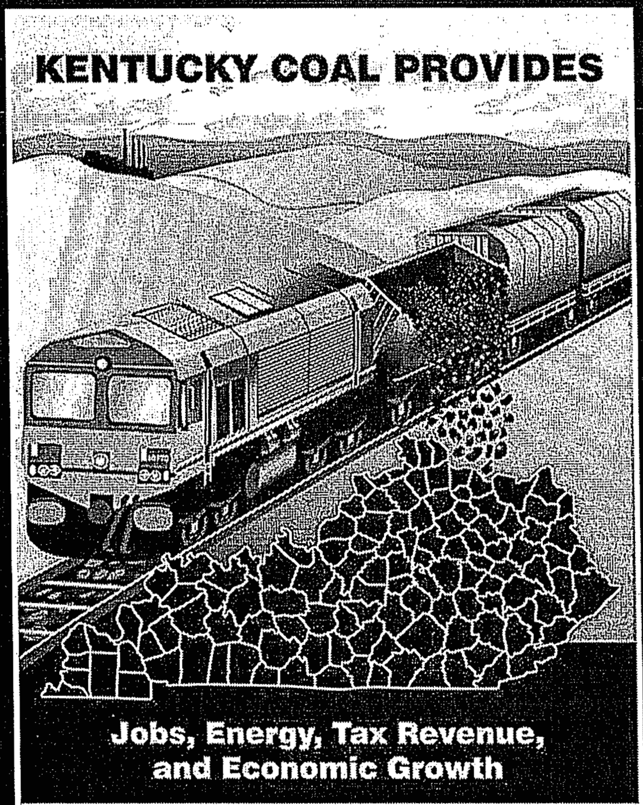
   Moreover, Western Kentucky also has sources of high sulfur coal that could potentially be used to increase the amount of Kentucky coal that the plant will consume when going to a 50% blend of NAPP/ILB coal.

b. Kentucky Power does not have a position on this hypothetical. As explained above, a 50/50 blend of either NAPP or ILB coals with CAPP coal would not necessarily reduce its purchases of Kentucky coal by 50%.

WITNESS: Ranie K Wohnhas

11th EDITION - POCKET GUIDE

KENTUCKY COAL FACTS



KIUC EXHIBIT 3

Coal Deliveries — State to State

In 2009, 106,147,054 tons of Kentucky coal was shipped to 26 states, including Kentucky. Georgia, South Carolina, and North Carolina were the largest purchasers of eastern Kentucky coal (50.4% combined). Kentucky was the principle consumer of western Kentucky coal (67%) and Florida, Ohio and Alabama were the principle out-of-state consumers (22.9% combined).

Destination of Coal Mined in Kentucky

Eastern Kentucky Coal

Destination State	Tons Shipped	Percent
Alabama	935,281	1.3%
Arkansas	4,769	0.0%
Delaware	572,077	0.8%
Florida	6,129,152	8.3%
Georgia	16,141,924	21.9%
Illinois	62,724	0.1%
Indiana	1,608,141	2.2%
Iowa	22,045	0.0%
Kentucky	6,872,354	9.3%
Louisiana	4,612	0.0%
Maryland	704,154	1.0%
Massachusetts	4,666	0.0%
Michigan	3,979,535	5.4%
Minnesota	143,198	0.2%
Mississippi	288,782	0.4%
Missouri	42,959	0.1%
New York	52,317	0.1%
North Carolina	9,137,388	12.4%
Ohio	5,961,403	8.1%
Oklahoma	10,869	0.0%
Pennsylvania	178,177	0.2%
South Carolina	11,893,458	16.1%
Tennessee	2,827,099	3.8%
Virginia	4,884,497	6.6%
West Virginia	1,033,146	1.4%
Wisconsin	248,074	0.3%
Total	**73,742,801**	**100.0%**

Western Kentucky Coal

Destination State	Tons Shipped	Percent
Alabama	1,560,766	4.8%
Florida	4,204,549	13.0%
Georgia	11,886	0.0%
Indiana	1,102,206	3.4%
Iowa	200,693	0.6%
Kentucky	**21,713,262**	**67.0%**
Missouri	395,493	1.2%
North Carolina	28,224	0.1%
Ohio	1,652,019	5.1%
Pennsylvania	116,458	0.4%
Tennessee	1,323,007	4.1%
Wisconsin	95,690	0.3%
Total	**32,404,253**	**100.0%**

Source of Coal Used in Kentucky

In 2009, 42,717,086 tons of coal were shipped to Kentucky from 11 states (including Kentucky). Of the 42.7 million tons delivered in Kentucky, 28.6 million tons (67%) originated in-state.

Origin State	Tons Shipped	Percent
Colorado	1,759,615	4.12%
Illinois	2,616,434	6.13%
Indiana	1,636,619	3.83%
Kentucky (East)	**6,872,354**	**16.09%**
Kentucky (West)	**21,713,262**	**50.83%**
Ohio	2,735,194	6.40%
Pennsylvania (Bituminous)	266,529	0.62%
Tennessee	53,367	0.12%
Utah	459,886	1.08%
Virginia	5,721	0.01%
West Virginia (Northern)	848,513	1.99%
West Virginia (Southern)	1,937,405	4.54%
Wyoming	1,812,187	4.24%
Total	**42,717,086**	**100.00%**

Source: U.S. DOE—Energy Information Administration, Annual Coal Distribution, 2009.

Release Date: April 2012
Next Release Date: June 2012

DOE/EIA-0121 (2011/04Q)

Quarterly Coal Report
October - December
2011

April 2012

U.S. Energy Information Administration
Office of Oil, Gas, and Coal Supply Statistics
U.S. Department of Energy
Washington, DC 20585

This report is available on the Web at:
http://www.eia.gov/coal/production/quarterly/

Table 2. Coal Production by State
(Thousand Short Tons)

Coal-Producing Region and State	October - December 2011	July - September 2011	October - December 2010	Year to Date		
				2011	2010	Percent Change
Alabama	4,261	4,507	4,613	19,060	19,915	-4.3
Alaska	578	491	609	2,149	2,151	-0.1
Arizona	2,049	2,031	2,086	8,111	7,752	4.6
Arkansas	28	27	26	133	32	312.8
Colorado	6,915	7,602	5,913	27,204	25,163	8.1
Illinois	9,435	10,204	8,449	37,441	33,241	12.6
Indiana	9,673	9,447	9,248	37,432	34,950	7.1
Kansas	24	8	42	37	133	-71.9
Kentucky Total	25,648	27,465	26,135	107,852	104,960	2.8
Eastern	15,575	17,001	16,873	67,024	68,063	-1.5
Western	10,073	10,464	9,263	40,828	36,897	10.7
Louisiana	972	1,156	1,084	3,865	3,945	-2.0
Maryland	740	653	528	2,555	2,585	-1.2
Mississippi	774	734	1,039	2,747	4,004	-31.4
Missouri	125	114	114	465	458	1.4
Montana	11,800	11,944	11,869	41,600	44,732	-7.0
New Mexico	5,004	5,011	5,100	21,922	20,991	4.4
North Dakota	7,769	6,918	7,210	28,214	28,949	-2.5
Ohio	7,370	6,868	6,651	28,115	26,707	5.3
Oklahoma	304	265	248	1,143	1,010	13.1
Pennsylvania Total	15,214	15,233	14,615	59,777	58,593	2.0
Anthracite	576	598	412	2,174	1,705	27.5
Bituminous	14,638	14,635	14,203	57,603	56,888	1.3
Tennessee	350	443	438	1,484	1,780	-16.6
Texas	11,173	12,497	10,731	45,773	40,982	11.7
Utah	5,134	4,828	4,771	19,463	19,351	0.6
Virginia	5,500	5,279	5,618	22,563	22,385	0.8
West Virginia Total	32,722	31,292	34,064	134,529	135,220	-0.5
Northern	10,404	9,157	11,287	41,838	41,306	1.3
Southern	22,318	22,136	22,777	92,691	93,914	-1.3
Wyoming	118,484	108,977	114,580	438,461	442,522	-0.9
Appalachian Total	**81,732**	**81,276**	**83,401**	**335,107**	**335,248**	**0.0**
Interior Total	**42,583**	**44,915**	**40,243**	**169,863**	**155,653**	**9.1**
Western Total	**157,733**	**147,804**	**152,137**	**587,124**	**591,611**	**-0.8**
East of Miss. River	**111,689**	**112,125**	**111,400**	**453,554**	**444,340**	**2.1**
West of Miss. River	**170,359**	**161,870**	**164,382**	**638,540**	**638,171**	**0.1**
U.S. Subtotal	**282,048**	**273,995**	**275,781**	**1,092,094**	**1,082,511**	**0.9**
Refuse Recovery	**403**	**631**	**398**	**2,241**	**1,857**	**20.7**
U.S. Total	**282,451**	**274,626**	**276,180**	**1,094,336**	**1,084,368**	**0.9**

Note: • Total may not equal sum of components because of independent rounding.
Source: • Mine Safety and Health Administration, U.S. Department of Labor, Form 7000-2, "Quarterly Mine Employment and Coal Production Report."

Kentucky Power Company

REQUEST

Identify and provide copies of any and all letters, comments, agreements, or other communications that have indicated financial or other support for Kentucky Power's application.

RESPONSE

Please see attachment 1 for all correspondence received by Kentucky Power in support of its application.

WITNESS: Ranie K Wohnhas

KIUC EXHIBIT 4

"Seth Schwartz"
<schwartz@evainc.com>
09/16/2011 03:31 PM

To <ggpauley@aep.com>
cc
bcc
Subject Committee to Save Big Sandy

History: This message has been forwarded.

Greg: I met with a number of people form the coal industry yesterday, most of whom run companies which are large ratepayers of Kentucky Power and employ many more ratepayers at their operations. I have written or verbal commitments from the attached list of members to support the Committee to Save Big Sandy. This group includes most of the coal mines in your service territory. The group is unanimous in its support for Kentucky Power to invest in emission control equipment on the Big Sandy plant. We want you to know that Kentucky Power will have broad support among the East Kentucky community for your upcoming filing at the PSC.

Our next step will be to contact the politicians in East Kentucky (county judge/executives, state representatives and state senators) to get them to support the investment to keep Big Sandy plant burning coal. You should begin hearing from them soon. Please let me know when you have been contacted so I know that they have followed through. I spoke with Rocky Adkins yesterday who told me that he has already spoken to you about keeping Big Sandy plant burning coal (the plant is in his district) and was quite emphatic about that.

Further, you should hear from Steve Miller of the national group, American Coalition for Clean Coal Electricity (Mike Morris is the chairman) to let you know that, if AEP files a plan to invest in burning coal at Big Sandy, ACCCE is prepared to file testimony in support of this plan.

Please keep me posted on the timing and status of your decision and we will keep you informed as to our efforts. Seth

Seth Schwartz
President
Energy Ventures Analysis, Inc.
1901 North Moore Street
Suite 1200
Arlington, VA 22209-1706
Phone: 703-276-4004 (direct)
Fax: 703-276-9541

Committee to Save Big Sandy member list 2011_09_16.docx

Committee to Save Big Sandy

Membership list 9/16/2011

		Contact		
Business	**Company**	**Last**	**First**	**Title**
Coal	Alden Resources	Smith	Keith	President
Coal	Alpha Coal	Crutchfield	Kevin	President
Coal	Alpha Coal	Jones	Monty	Senior VP
Coal	Apex Energy	Campbell	Mark	VP
Coal	Arch Coal	Eaves	John	President
Coal	Arch Coal	Slone	Deck	VP, Public Affairs
Coal	Beech Fork	Booth	Jim	CEO
Coal	Blackhawk Mining	Glancy	Nick	President
Coal	Blue Energy Services	Helms	Ted	President
Coal	Helping Hands	Smith	John	President
Coal	Nally & Hamilton	Hamilton	Steve	Sec.-Treasurer
Coal	Old Virginia	Kiscaden	Scott	President
Coal	Revelation Energy	Hoops	Jeff	President
Coal	Rhino Energy	Moravec	Chris	VP
Coal	Southern Coal Corp	Merritt	Marc	
Coal	Xinergy	Castle	Mike	CFO
Coal	Xinergy	Nix	Jon	President
Consulting	Energy Ventures Analysis	Schwartz	Seth	President
Group	Coal Operators & Associates	Gooch	David	President
Group	Kentucky Coal Association	Bissett	Bill	President
Land	Marwood Land	Parrish	Lynn	
Land	Natural Resource Partners	Carter	Nick	President
Law	Jackson & Kelly	Nicholson	Roger	Partner
Law	Wyatt, Tarrant & Combs	Woods	Jeff	Partner
Rail	CSX	Jenkins	Chris	VP, Coal

COMMITTEE TO SAVE THE BIG SANDY POWER PLANT

1. AEP Kentucky Power serves the East Kentucky coal fields. Most of the economic activity and jobs in AEP's service territory are related to coal mining and support services. Over one-third of the entire industrial load of Kentucky Power is coal mines.
2. Kentucky Power owns only one power plant, the 1,060 MW Big Sandy plant, located in Louisa, Kentucky, which provides most of the power to this service territory. The Big Sandy plant burns about 2.5 million tons per year of coal, almost all mined in East Kentucky (a little comes from West Virginia). In 2010, this plant spent $175 million on coal purchases.
3. New EPA regulations proposed in 2011 (Utility MACT and Cross-State Air Pollution Rule) will require AEP to invest in new emission controls (scrubbers) in order to keep burning coal at Big Sandy, or close the plant.
4. AEP has not yet decided whether to invest in keeping the Big Sandy plant open. Originally, AEP planned to build scrubbers at Big Sandy, but recently AEP has announced that the plant may be closed and replaced with a new natural gas plant, because of EPA's new regulations.
5. Whether AEP invests in Big Sandy or closes it and replaces it with gas, the ratepayers of Kentucky Power will be faced with a large rate increase to pay for compliance with the new EPA regulations. The coal mining community of East Kentucky believes that Kentucky Power should invest in the Big Sandy plant because the jobs and tax revenues from this plant support the entire area.
6. The coal produced to supply Big Sandy provides the local area over 500 direct mining jobs, severance taxes over $8 million per year, and wages over $25 million per year. In addition, the coal burned by Big Sandy supports jobs for suppliers and truckers, as well as taxes for the local schools and governments.
7. National environmental groups are intervening in Kentucky's rate cases to try to force utilities to close power plants burning Kentucky coal. The local community, who are Kentucky Power's largest ratepayers, support investing in Big Sandy and burning Kentucky coal. We need the support of the elected representatives of East Kentucky to save the Big Sandy power plant.

COMMITTEE TO SAVE THE BIG SANDY POWER PLANT

c/o Energy Ventures Analysis, Inc.
1901 North Moore Street
Suite 1200
Arlington, VA 22209
703-276-8900

Background

Kentucky Power Company ("KPCo", a subsidiary of AEP) has announced that it may close the Big Sandy coal-fired power plant in response to the environmental requirements proposed by EPA (including the Utility MACT to take effect in 2015 and CSAPR in 2012 and 2014). KPCo has stated that it has not made a final decision, but it plans to make a decision this month (September) and file with the Kentucky Public Service Commission ("KPSC") in October for approval of its plan and recovery of the cost in its rates. The current plan is to retire Big Sandy unit #2 (800 MW) in 2014 and convert Big Sandy unit #1 (260 MW) to natural gas.

The Big Sandy plant is one of the largest single markets for East Kentucky coal. It consumes 2.5 mm tpy of coal in an average year, which is close to 5% of the entire current demand for East Kentucky coal. Given the outlook for declining domestic steam coal demand due to the new EPA regulations, the importance of this plant to East Kentucky will grow in the future. At market prices of about $75 per ton, the coal sales to Big Sandy inject $187.5 mm per year into the local economy, including over 500 direct coal mining jobs, wages over $25 mm per year and severance taxes of $8.4 mm per year.

Further, the vast majority of KPCo's power sales are to ratepayers in the coal fields of East Kentucky. Over one-third of KPCo's entire industrial power sales are to coal mines. It is in the interest of the ratepayers of KPCo to pay for the costs of the scrubber investment in their power prices rather than bear the economic calamity to the region which would come from closing this plant and paying higher rates for gas-fired power.

Purpose of the Committee to Save Big Sandy

KPCo is open to spending the capital to invest in emission controls at Big Sandy (mainly scrubbers), but has been discouraged by political opposition to the rate increases needed to pay for it by state legislators and local county executives. The purpose of the Committee is to gather the political support in the East Kentucky community to influence the politicians to support the investment its inclusion in the rate base. We believe that KPCo will propose the scrubber investment to the KPSC if the politicians express their support.

The Committee is a special-purpose public interest organization formed to intervene in KPCo's rate case to support KPCo's plan to invest in the plant. We plan to retain counsel and file testimony. However, if KPCo files a plan to close the Big Sandy plant, the Committee would plan to intervene in the rate case to oppose KPCo's plan and contest its recovery of its existing investment in Big Sandy after it is closed. Hopefully, it will not come to that step, but the credible threat to oppose KPCo is almost as important as the commitment to support KPCo in a plan to invest in Big Sandy plant.

Immediate Action Plan

In order to have credibility, the Committee needs a broad membership among the coal producers, shippers, miners, landowners and stakeholders of East Kentucky. We will provide a membership list with prominent names and companies to KPCo to show the degree of support and influence which we have among the industry. I have talked with the President of Kentucky Power, Greg Pauley, and he has asked for a proposal as to what we can do to support KPCo with the politicians.

Accordingly, the first thing that we need is for you to fill out and return the attached membership form immediately, so we can represent a large group of stakeholders to KPCo.

We do not have an immediate need to raise money but will ask for contributions in the future.

Please act now to save Big Sandy plant, our jobs and the local community. There are too many well-funded organizations working to close existing coal-fired plants. Let's fight back to save them when we can. I welcome your feedback and support.

Seth Schwartz
Director, Committee to Save Big Sandy
703-276-9541
schwartz@evainc.com

COMMITTEE TO SAVE THE BIG SANDY POWER PLANT

Membership Form

Contact ______________________________

Company ______________________________

Address ______________________________

City/ST/Zip ______________________________

Phone ______________________________

Email ______________________________

Are you or your company a ratepayer of Kentucky Power at any location?

Yes ____ No ____

Gregory G Pauley/OR3/AEPIN
01/18/2012 12:58 PM

To Thomas P Householder/OR4/AEPIN@AEPIN
cc
bcc
Subject Re: Union Assistance

Thanks Tom Appreciated Let me share some thoughts on this and if you'd like to talk give me a call.

For a Kentucky issue it might be better to use AEP - Kentucky Power. Legislators outside our territory might not identify with American Electric Power but would recognize the Kentucky Power brand. Also, if they decide to send a letter it would be just as effective, if not more so, to include the County Judge Executives in our service territory who have as much, if not more, influence than the Rep/Senator.

There will also be 4 public hearings in the territory between now and when the decision is made. Such support, in person, would be beneficial to the cause. I'm sure the meetings will be inundated with those in the community opposing the decision based on the proposed rate increase. These will be people who support coal and all it does for them - they just don't want anymore increases to their electric bill.

Lastly, the decision to scrub Big Sandy II was based on the existing regulatory compact (process and proceedings) which allows for the recovery of such expenses through an envrionmental cost recovery statute. Should the legislators enact legislation during the 2012 session that modifies the existing regulatory compact it will make it necessary to revisit our decision. I have made it very clear in presentations throughout the service territory that negative changes would result in a review and reconsideration of the submission before the commission. We want to do all we can to let the process work and get a decision the is good for the company, customers and shareholders.

Question for you - Are they doing this on their part or per our request? There is a fine line there and an important point.

Thanks Tom

Gregory G. Pauley
President & COO
AEP - Kentucky Power Co.
101A Enterprise Drive
Frankfort, Kentucky 40601

Office 502-696-7007
Audinet (AEP) 605-7007
Cell 502-545-7007
Fax 502-696-7006

Thomas P Householder/OR4/AEPIN

Thomas P Householder/OR4/AEPIN
01/17/2012 04:19 PM

To Gregory G Pauley/OR3/AEPIN@AEPIN

cc

Subject Union Assistance

Greg, any comments would be appreciated . I will channel your comments to and through the unions. If you do not want any letters let me know and I will back them off. In Ohio and West Virginia, I have sought the unions' support in the past. Thanks

---

Thomas P. Householder
American Electric Power
Managing Director - Labor Services
1 Riverside Plaza - 17th Floor
Columbus, OH 43215
614 / 716-1713 or Audinet 200-1713
Cell: 614-562-1425

----- Forwarded by Thomas P Householder/OR4/AEPIN on 01/17/2012 04:12 PM -----

"Michael Autry"
<mautry@boilermakerslocal40.com>
01/17/2012 03:55 PM

To "Thomas P. Householder" <tphouseholder@aep.com>

cc

Subject

Tom,

Just wanted to let you know, we are doing a letter writing campaign to all of our Representatives and Senators asking them to support AEP'S request for Big Sandy Power Plants rate increase to be approved by the Kentucky Public Service Commission. I have attached a copy of the letter I am preparing to send to my Senator and Representative. Please look it over and if you see anything I need to add or remove, please let me know.

I am in the process of making this a form letter for all of our members to use state wide. Also, we will be creating another letter similar to this one to send to the Kentucky Public Service Commission representatives.

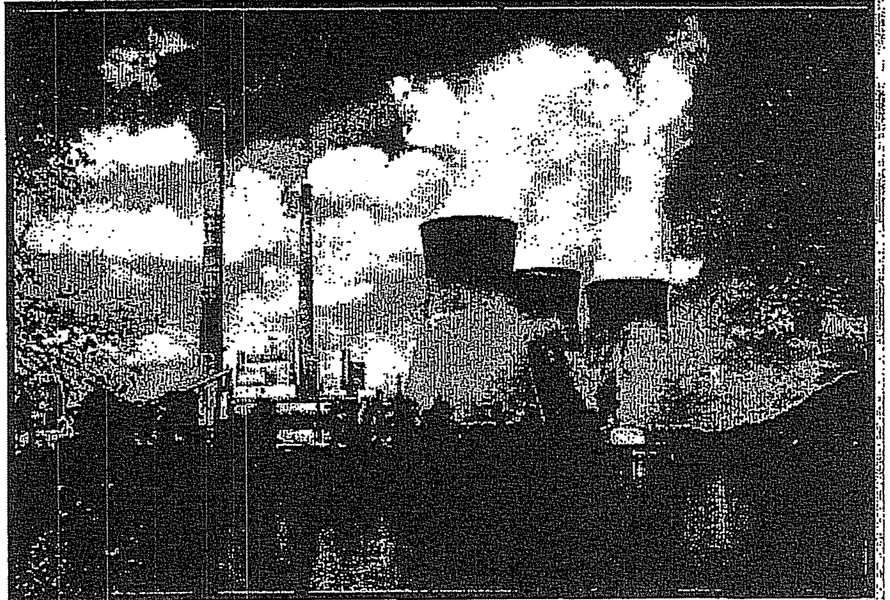
Thanks and best wishes,
Michael W. Autry

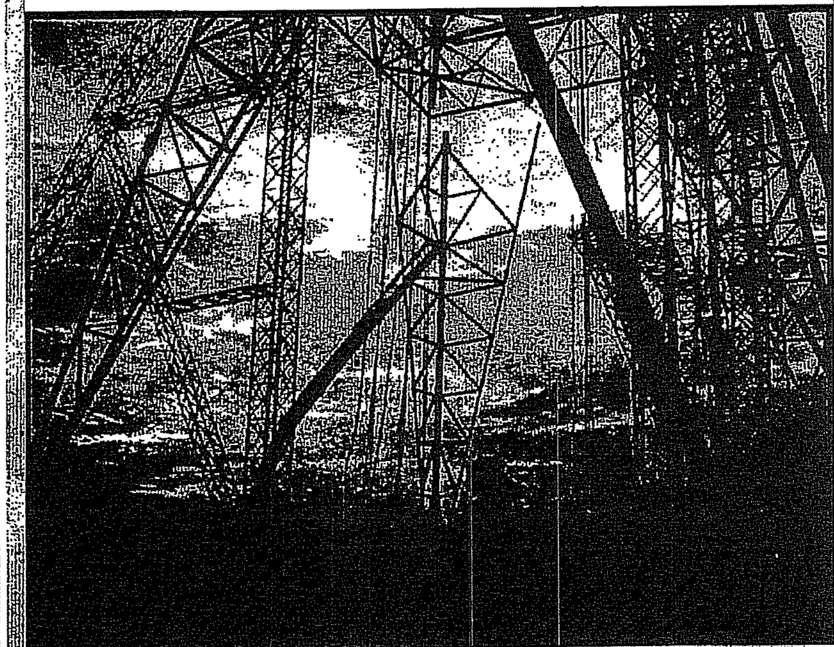
Autry, Michael W.
Boilermakers Local 40
Business Manager
(270) 769-3024 Work
(270) 256-2525 Mobile
(270) 274-0011 Home
mautry@boilermakerslocal40.com
l40@boilermakerslocal40.com
429 Commerce Drive
Elizabethtown, KY 42701

EXHIBIT ____ (LK-8)

KIUC EXHIBIT 5

AEP AMERICAN® ELECTRIC POWER





46th EEI Financial Conference Presentation

Orlando, FL
November 8, 2011

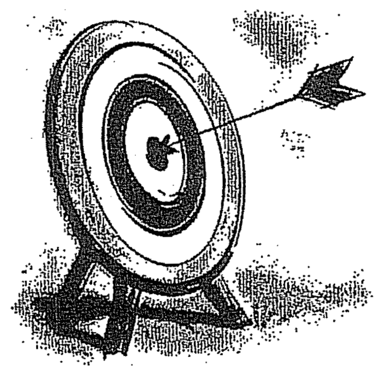
Nick Akins

President and CEO-elect

American Electric Power

My areas of strategic focus...

1. Optimize the earnings stream of the Company
   - ROE optimization
   - Resource transformation
   - Reposition transmission business
2. Achieve regulatory certainty
   - Execute Ohio strategy
   - Energy policy, EPA and environmental investments
3. Earnings and dividend growth



ROE optimization...

ROE by Jurisdiction

Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia	10.53%	
APCO – West Virginia	10.00%	6.88%
Wheeling	10.00%	
I&M – Indiana	10.50%	8.24%
I&M – Michigan	10.35%	
SWEPCO – Louisiana	10.57%	
SWEPCO – Arkansas	10.25%	10.05%
SWEPCO – Texas	10.33%	
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

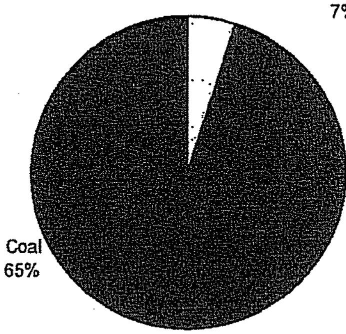
- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

Management focused on Operating Company results and rate plans

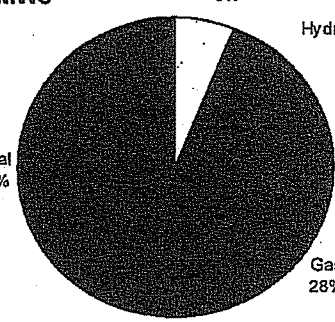
Resource transformation . . .

- Grow rate base and earnings through adding environmental controls
- Retire older, uncontrolled coal units
- Add new capacity (natural gas) to rate base to replace a portion of retirements
- Transformation already occurring due to shale gas

2010 AEP Generating Capacity by Fuel 39,910 total MWs



2020 AEP Generating Capacity by Fuel 37,707 total MWs



Need more time to accomplish in order to mitigate customer costs and reliability impacts

EXHIBIT ____ (LK-9)

KIUC EXHIBIT 6

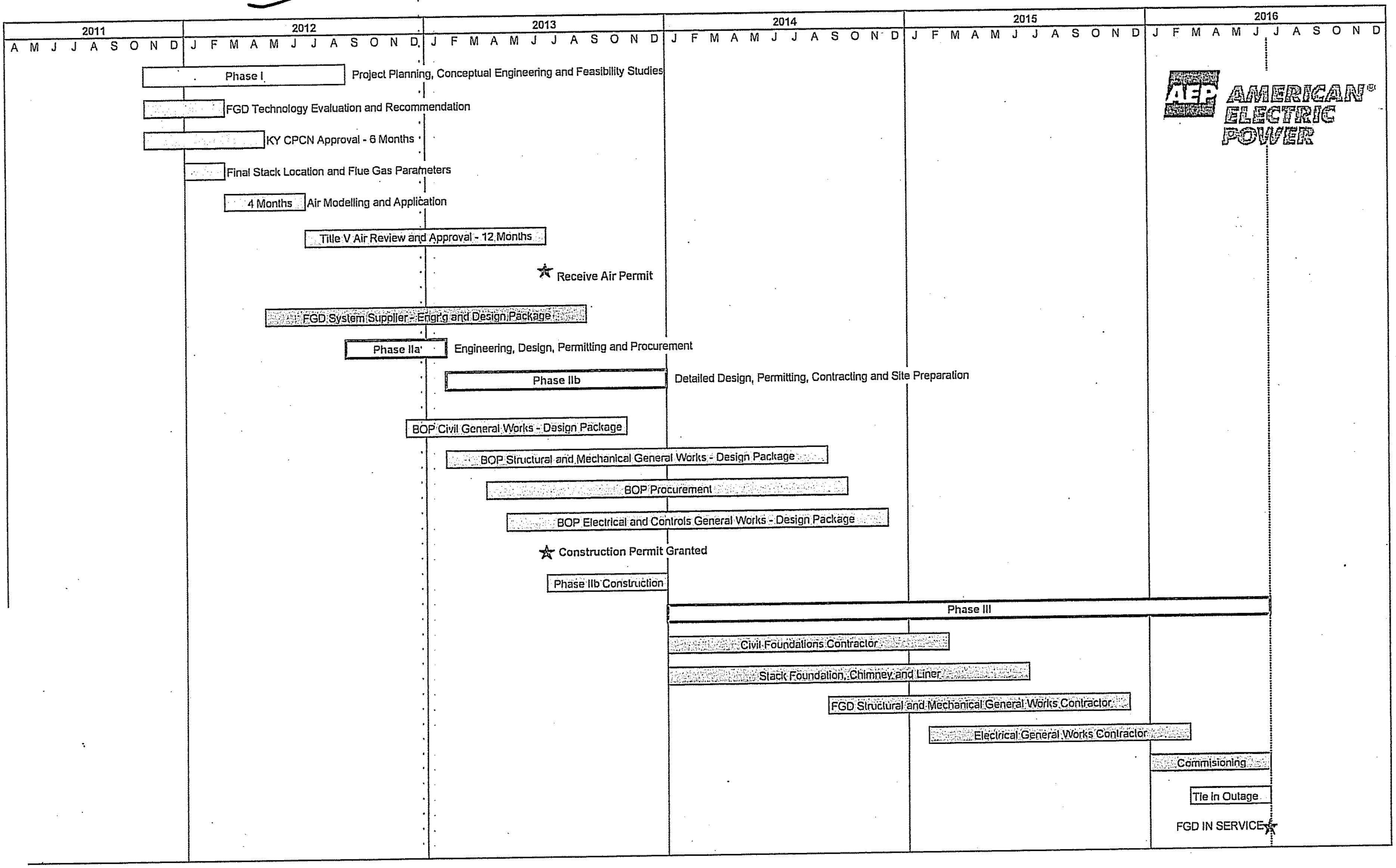
(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

And

In the Confidential File Materials at the PSC

KIUC 7



KIUC EXHIBIT 7

Kentucky Power Company

REQUEST

Provide a revised version of the least-cost analysis used in all of Kentucky Power's original testimony and data responses to date to reflect current conditions within the industry. Provide supporting details and sources for all assumptions, data, and regulatory requirements that drive specific alternatives. Include support for capital costs. Indicate timing issues that may arise with certain alternatives, including environmental requirements. Consider and account for any recent regulatory changes in Ohio or other states that may change the supply chain or availability of materials, equipment, or services. Include at a minimum:

a. PJM energy and capacity costs going forward;

b. Gas prices going forward;

c. Coal prices going forward;

d. Current energy and peak demand projections;

e. Current capital costs for all projects under consideration;

f. Include all previous alternatives, if still available, as well as any new alternatives that may now be available;

g. Consider any recent regulatory changes in Ohio or other states that may change the supply mix or availability;

h. Consider a range of costs for CO_2;

i. Consider a five-year purchased power approach, as well as any longer periods that may be optimum.

RESPONSE

KIUC EXHIBIT 8

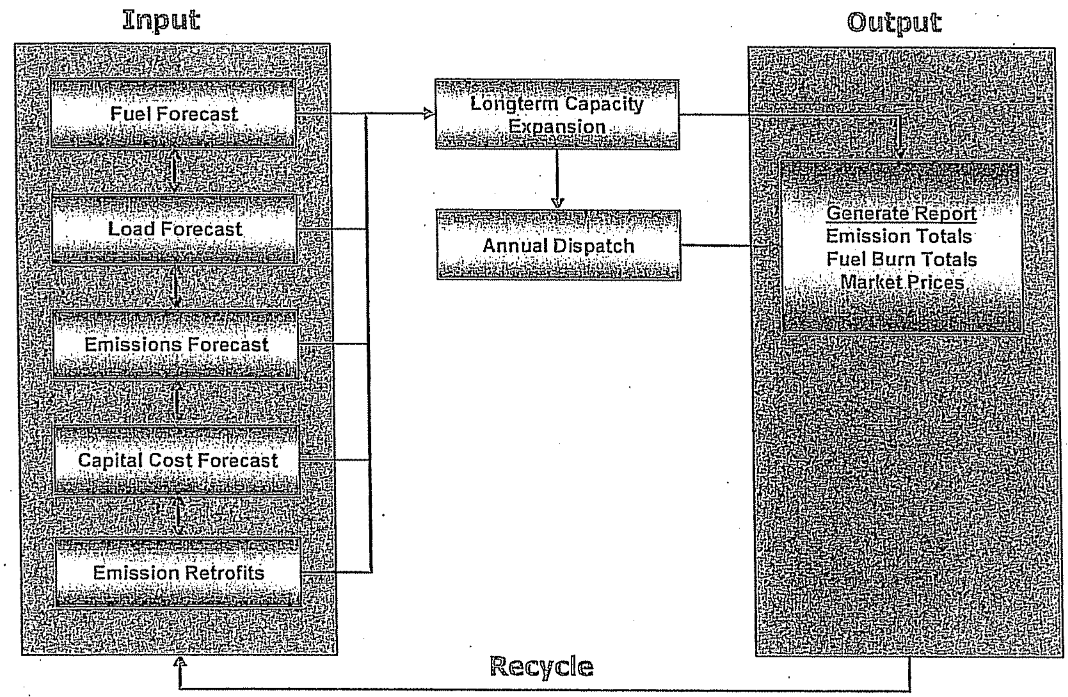
The Company has not revised any of the least cost analyses provided in its testimony or subsequent data responses. The data used in those analyses remains the most current data available. The Long-Term Forecast begins with a fundamental view of the primary input drivers (fuel supply, load, impending regulatory policy, capital costs, etc.) which is developed by internal subject-matter experts and benchmarked to public and contract consultants' information. A third-party dispatch model, Aurora^{XMP}, takes the long-term view of these primary drivers and, after multiple iterations requiring correlative input changes, delivers PJM energy and capacity values, peak demand projections and other power market parameters. The process of creating the Long-Term Forecast takes approximately two months to complete. In addition, it would take another 4 weeks of Strategist work to complete all of the modeling. To this point, there have been no meaningful changes to the primary drivers and accordingly there would be no material differences if the analyses were run to reflect the April 1, 2012 condition in the industry.

In particular:

Natural Gas; The extraordinarily mild 2011-2012 heating season has caused nearby natural gas spot prices to drop to sub-$2/mmBtu levels due to high storage inventories and certain summer storage re-fill congestion. It is equally likely that, in the event of a colder-than-normal heating season, natural gas spot prices could exceed $7/mmBtu. But, on a weather-normalized basis, the fundamentals of natural gas production costs to meet the anticipated total natural gas demand still results in prices equivalent to those projected in Kentucky Power's original testimony for 2013 and beyond. The dominant factor for this observation is that the long-term projection for exploration, development and production costs for shale gas remains unchanged – thus creating a "floor" price. While natural gas prices may incur additional environmental costs due to the process of hydro-fracturing, additional "associated gas" may be brought to market because of the economic advantage of oil/liquids-rich shale plays. But, at this time, there is no reasonable justification to alter the long-term outlook for natural gas prices to Kentucky Power.

Coal; Kentucky Power Company's coal forecast was based upon the long-term costs of coal production and the demand associated with normal weather. It includes assessments of coal-fired plant retirements due to impending environmental regulations and projections of US coal exports due to rising global demand - and these conditions remain unchanged. For the near term, the forecast coal prices will be affected by many other factors, including weather, competing fuel and utility coal stockpile levels. The mild 2011-2012 heating season along with inexpensive natural gas have made coal-fired plant dispatch lower than expected and has left utilities with high stockpiles. This over-supply of coal in the near-term depresses coal prices to such low levels that they are below the cost of production for many less-efficient mines. Coal producers have started to cut down their production to re-balance the supply-demand relationship, and coal prices will recover to cost-of-production based levels in the near-term. Therefore, the forecast prices for the long-term remain valid.

Capacity, energy and peak-demand; The third-party dispatch model, Aurora^{XMP}, has power market values/prices as "outputs" (as shown in the illustration below). Given that there has been no substantive change to the long-term view of the primary input drivers, the outputs and, therefore, the Long-Term Forecast, should remain unchanged.



A range of costs for CO_2; Without question, the creation of a Long-Term Forecast which considers a range of CO_2 costs must include correlative changes to other input drivers. It is imprudent to ignore: 1) the effect of coal plant dispatch costs on coal prices due to changes in demand, 2) changes in gas-fired plant utilization and the effect on natural gas prices, 3) changes in plant retirement schedules, 4) the price elasticity of residential, commercial and industrial demand, for example. The necessary "feedback" loops" (iterations) to create a prudent set of Long-Term Forecasts with a range of costs for CO_2 will require two months to complete.

The Company has not updated any of the capital costs for any of the alternatives and those alternatives provided in the original testimony are still the only alternatives the Company believes are available.

AEP made a filing at FERC in early February 2012 that included a new Power Cost Sharing Agreement (PCSA) that would replace the current pool agreement. As part of the proposed PCSA, KPCo would have purchased a 20% ownership in Mitchell Units 1 and 2. That filing has since been withdrawn, but the Company anticipates resubmitting another filing at a later time this year that will include the purchase of 20% of the Mitchell Units. The transfer of Ohio Power (OPCo) generation to sister companies within AEP was proposed specifically for purposes of supporting the new PCSA. KPCo has no other rights to any additional OPCo generation nor does OPCo have any obligation to KPCo with any additional generation. The Company lacks a reasonable basis to project the availability or price of any additional Ohio generation.

The Company in its application prepared alternative #4A and #4B that looked at both a 5 and 10 year purchase power approach and then would either build or replace with CC capacity. The Company is not able to consider other alternative options at the end of the purchased power approach in the time required to respond to this data request. At a minimum, it would take 8 to 10 weeks to perform the necessary due diligence to evaluate the change in costs due to delaying the DFGD project and economic evaluation of such changes through our modeling exercises.

WITNESS: Scott C Weaver

KIUC EXHIBIT 9

Summary of Long-Term Commodity Price Forecast Scenarios

(Source: AEP Fundamental Analysis)
Annual Average (Nominal Dollars)

NATURAL GAS (Henry Hub)
($/MMBtu)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	4.48	4.48	3.94	4.48	4.48
2013	4.94	5.43	4.35	4.94	4.94
2014	5.38	6.02	4.73	5.38	5.38
2015	5.52	6.29	4.86	5.52	5.52
2016	5.99	6.94	5.27	5.99	5.99
2017	6.13	7.23	5.39	6.42	6.13
2018	6.32	7.46	5.56	6.60	6.32
2019	6.46	7.62	5.68	6.73	6.46
2020	6.52	7.69	5.73	6.78	6.52
2021	6.75	7.97	5.94	7.06	6.60
2022	7.07	8.34	6.22	7.22	6.68
2023	7.26	8.57	6.39	7.35	6.86
2024	7.51	8.86	6.61	7.51	7.10
2025	7.75	9.14	6.82	7.75	7.32
2026	7.85	9.26	6.91	7.85	7.42
2027	8.04	9.49	7.08	8.04	7.60
2028	8.22	9.78	7.23	8.22	7.77
2029	8.41	10.08	7.40	8.41	7.94
2030	8.52	10.48	7.50	8.52	8.05

CO_2
($/Metric Tonne)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	15.08	0.00
2018	0.00	0.00	0.00	15.28	0.00
2019	0.00	0.00	0.00	15.47	0.00
2020	0.00	0.00	0.00	15.68	0.00
2021	0.00	0.00	0.00	15.88	0.00
2022	15.08	15.48	15.48	16.08	0.00
2023	15.28	15.67	15.67	16.29	0.00
2024	15.48	15.88	15.88	16.50	0.00
2025	15.67	16.08	16.08	16.72	0.00
2026	15.88	16.29	16.29	16.94	0.00
2027	16.08	16.50	16.50	17.16	0.00
2028	16.29	16.72	16.72	17.38	0.00
2029	16.50	16.94	16.94	17.60	0.00
2030	16.72	17.12	17.16	17.84	0.00

NAPP (6.0#)
($/Ton-FOB Mine)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	56.75	64.13	53.91	56.75	56.75
2013	58.00	66.70	53.36	58.00	58.00
2014	60.00	69.00	53.40	60.00	60.00
2015	62.36	72.34	55.50	62.36	62.36
2016	64.72	75.08	57.60	64.72	64.72
2017	65.92	76.47	58.67	64.00	65.92
2018	67.18	77.93	59.79	65.22	67.18
2019	68.45	79.40	60.92	66.46	68.45
2020	69.71	80.87	62.05	67.68	69.71
2021	71.18	82.57	63.35	69.10	71.18
2022	70.90	82.24	63.10	70.55	72.67
2023	72.37	83.95	64.41	72.02	74.18
2024	73.87	85.69	65.74	73.51	75.71
2025	75.38	87.44	67.09	75.01	77.26
2026	76.91	89.22	68.45	76.54	78.84
2027	78.46	91.02	69.83	78.08	80.43
2028	80.04	92.85	71.24	79.65	82.04
2029	81.65	94.71	72.66	81.25	83.69
2030	83.27	96.60	74.11	82.87	85.36

CAPP (1.6#)
($/Ton-FOB Mine)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	79.97	91.46	75.97	79.97	79.97
2013	83.46	97.95	75.11	83.46	83.46
2014	84.83	101.44	74.65	84.83	84.83
2015	85.21	102.25	74.98	85.21	85.21
2016	85.52	102.62	75.26	85.52	85.52
2017	85.31	102.37	75.07	82.83	85.31
2018	86.94	104.33	76.51	84.41	86.94
2019	88.58	106.30	77.95	86.00	88.58
2020	90.22	108.26	79.39	87.59	90.22
2021	92.07	110.48	81.02	89.38	92.07
2022	91.66	109.99	80.66	91.21	93.95
2023	93.52	112.22	82.30	93.07	95.86
2024	95.41	114.49	83.96	94.94	97.79
2025	97.31	116.77	85.63	96.84	99.74
2026	99.24	119.09	87.33	98.76	101.72
2027	101.19	121.43	89.05	100.70	103.72
2028	103.18	123.81	90.80	102.68	105.76
2029	105.19	126.23	92.57	104.68	107.82
2030	107.24	128.69	94.37	106.72	109.92

ON-Peak Energy (PJM-AEP Gen Hub)
($/Mwh)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	50.57	55.16	47.59	49.73	50.30
2013	50.14	55.48	44.98	48.59	47.85
2014	54.24	62.03	49.26	54.28	54.45
2015	56.71	65.49	53.60	56.42	56.79
2016	63.56	71.80	58.75	62.42	63.74
2017	63.48	71.72	59.20	71.84	64.41
2018	64.18	73.15	60.06	72.73	65.25
2019	65.44	74.08	60.90	73.21	66.31
2020	66.33	75.16	60.86	73.82	66.55
2021	67.64	77.00	62.38	75.75	67.28
2022	76.79	85.88	72.64	77.34	68.31
2023	78.33	87.97	74.25	78.43	70.32
2024	80.34	89.78	74.99	79.55	71.04
2025	82.18	92.27	76.25	81.48	73.07
2026	83.23	93.67	77.71	82.70	73.94
2027	84.57	95.54	79.22	84.24	75.28
2028	86.25	98.14	80.55	86.25	76.51
2029	87.64	100.30	81.53	87.32	77.70
2030	89.34	103.70	82.78	88.75	78.95

OFF-Peak Energy (PJM-AEP Gen Hub)
($/Mwh)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	30.92	33.66	29.07	30.33	30.27
2013	30.55	35.01	28.55	30.15	29.97
2014	33.26	38.84	31.15	32.95	33.34
2015	33.89	40.47	32.16	33.73	34.34
2016	39.57	45.94	36.16	38.65	40.12
2017	41.57	48.09	38.59	51.00	41.67
2018	42.57	49.48	39.25	52.03	42.70
2019	43.60	50.18	40.01	52.82	43.47
2020	44.18	51.40	40.52	53.54	44.35
2021	45.76	53.01	41.76	55.14	45.22
2022	55.93	63.44	52.41	56.56	46.22
2023	56.84	65.25	53.42	57.35	47.67
2024	58.85	66.65	54.17	58.69	48.94
2025	60.37	68.79	55.93	60.38	50.72
2026	61.06	70.11	56.67	61.28	51.59
2027	62.64	72.07	58.15	62.85	53.19
2028	64.05	74.08	59.05	64.56	54.40
2029	65.66	76.20	60.20	65.80	55.78
2030	67.49	78.87	61.12	66.82	56.65

Capacity Value (PJM-RTO RPM)
($/MW-Day)

	'BASE'	Alternative Scenarios			
	Fleet Transition: CSAPR Carbon in 2022	FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	16.46	16.46	16.46	16.46	16.46 *
2013	27.73	27.73	27.73	27.73	27.73 *
2014	126.00	126.00	126.00	126.00	126.00 *
2015	215.25	215.25	215.25	215.25	215.25
2016	281.92	281.92	281.92	281.92	281.92
2017	235.98	199.63	230.85	210.98	240.98
2018	200.39	166.43	179.76	180.39	205.39
2019	224.57	211.40	186.64	214.57	230.57
2020	253.47	253.86	212.57	243.47	261.47
2021	280.05	293.65	238.70	265.05	295.05
2022	304.18	330.64	264.71	289.18	322.18
2023	325.73	364.68	288.14	310.73	345.73
2024	344.58	391.96	308.40	329.58	364.58
2025	360.58	405.21	325.58	345.58	380.58
2026	373.61	411.28	340.04	358.61	394.61
2027	383.50	417.45	350.60	363.50	405.50
2028	390.13	423.72	358.23	370.13	413.13
2029	392.94	430.07	362.96	372.94	416.94
2030	392.16	436.27	361.29	372.16	418.16

* *Represents PJM-RTO (i.e. "western" or "rest-of-market" PJM) Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years*

Henry Hub

				Date: 4/30/2012			
Location	*Term*	*Product*	*Source*	*As Of*	*Price*	*Units*	*% Change*
Henry Hub	Nov 2011	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	Dec 2011	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	Jan 2012	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	Feb 2012	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	Mar 2012	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	Apr 2012	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	May 2012	Natural Gas Futures	NYMEX	04/30/2012	-	$/MMBtu	-
Henry Hub	Jun 2012	Natural Gas Futures	NYMEX	04/30/2012	2.285	$/MMBtu	4.53
Henry Hub	Jul 2012	Natural Gas Futures	NYMEX	04/30/2012	2.394	$/MMBtu	4.13
Henry Hub	Aug 2012	Natural Gas Futures	NYMEX	04/30/2012	2.462	$/MMBtu	3.66
Henry Hub	Sep 2012	Natural Gas Futures	NYMEX	04/30/2012	2.509	$/MMBtu	3.59
Henry Hub	Oct 2012	Natural Gas Futures	NYMEX	04/30/2012	2.600	$/MMBtu	3.38
Henry Hub	Nov 2012	Natural Gas Futures	NYMEX	04/30/2012	2.852	$/MMBtu	2.77
Henry Hub	Dec 2012	Natural Gas Futures	NYMEX	04/30/2012	3.182	$/MMBtu	2.35
Henry Hub	Jan 2013	Natural Gas Futures	NYMEX	04/30/2012	3.337	$/MMBtu	2.05
Henry Hub	Feb 2013	Natural Gas Futures	NYMEX	04/30/2012	3.349	$/MMBtu	1.92
Henry Hub	Mar 2013	Natural Gas Futures	NYMEX	04/30/2012	3.326	$/MMBtu	1.84
Henry Hub	Apr 2013	Natural Gas Futures	NYMEX	04/30/2012	3.303	$/MMBtu	1.79
Henry Hub	May 2013	Natural Gas Futures	NYMEX	04/30/2012	3.342	$/MMBtu	1.67
Henry Hub	Jun 2013	Natural Gas Futures	NYMEX	04/30/2012	3.392	$/MMBtu	1.59
Henry Hub	Jul 2013	Natural Gas Futures	NYMEX	04/30/2012	3.448	$/MMBtu	1.53
Henry Hub	Aug 2013	Natural Gas Futures	NYMEX	04/30/2012	3.469	$/MMBtu	1.52
Henry Hub	Sep 2013	Natural Gas Futures	NYMEX	04/30/2012	3.472	$/MMBtu	1.52
Henry Hub	Oct 2013	Natural Gas Futures	NYMEX	04/30/2012	3.507	$/MMBtu	1.48
Henry Hub	Nov 2013	Natural Gas Futures	NYMEX	04/30/2012	3.629	$/MMBtu	1.37
Henry Hub	Dec 2013	Natural Gas Futures	NYMEX	04/30/2012	3.841	$/MMBtu	1.29
Henry Hub	Jan 2014	Natural Gas Futures	NYMEX	04/30/2012	3.952	$/MMBtu	1.26
Henry Hub	Feb 2014	Natural Gas Futures	NYMEX	04/30/2012	3.932	$/MMBtu	1.26
Henry Hub	Mar 2014	Natural Gas Futures	NYMEX	04/30/2012	3.874	$/MMBtu	1.28
Henry Hub	Apr 2014	Natural Gas Futures	NYMEX	04/30/2012	3.718	$/MMBtu	1.23
Henry Hub	May 2014	Natural Gas Futures	NYMEX	04/30/2012	3.739	$/MMBtu	1.25
Henry Hub	Jun 2014	Natural Gas Futures	NYMEX	04/30/2012	3.773	$/MMBtu	1.23
Henry Hub	Jul 2014	Natural Gas Futures	NYMEX	04/30/2012	3.814	$/MMBtu	1.22
Henry Hub	Aug 2014	Natural Gas Futures	NYMEX	04/30/2012	3.832	$/MMBtu	1.22
Henry Hub	Sep 2014	Natural Gas Futures	NYMEX	04/30/2012	3.835	$/MMBtu	1.21
Henry Hub	Oct 2014	Natural Gas Futures	NYMEX	04/30/2012	3.870	$/MMBtu	1.18
Henry Hub	Nov 2014	Natural Gas Futures	NYMEX	04/30/2012	3.962	$/MMBtu	1.15
Henry Hub	Dec 2014	Natural Gas Futures	NYMEX	04/30/2012	4.152	$/MMBtu	1.10
Henry Hub	Jan 2015	Natural Gas Futures	NYMEX	04/30/2012	4.247	$/MMBtu	1.00
Henry Hub	Feb 2015	Natural Gas Futures	NYMEX	04/30/2012	4.219	$/MMBtu	1.01
Henry Hub	Mar 2015	Natural Gas Futures	NYMEX	04/30/2012	4.139	$/MMBtu	1.03
Henry Hub	Apr 2015	Natural Gas Futures	NYMEX	04/30/2012	3.927	$/MMBtu	0.95
Henry Hub	May 2015	Natural Gas Futures	NYMEX	04/30/2012	3.943	$/MMBtu	0.95
Henry Hub	Jun 2015	Natural Gas Futures	NYMEX	04/30/2012	3.968	$/MMBtu	0.94
Henry Hub	Jul 2015	Natural Gas Futures	NYMEX	04/30/2012	4.004	$/MMBtu	0.93
Henry Hub	Aug 2015	Natural Gas Futures	NYMEX	04/30/2012	4.022	$/MMBtu	0.93
Henry Hub	Sep 2015	Natural Gas Futures	NYMEX	04/30/2012	4.026	$/MMBtu	0.93
Henry Hub	Oct 2015	Natural Gas Futures	NYMEX	04/30/2012	4.062	$/MMBtu	0.92
Henry Hub	Nov 2015	Natural Gas Futures	NYMEX	04/30/2012	4.152	$/MMBtu	0.90
Henry Hub	Dec 2015	Natural Gas Futures	NYMEX	04/30/2012	4.342	$/MMBtu	0.86
Henry Hub	Jan 2016	Natural Gas Futures	NYMEX	04/30/2012	4.437	$/MMBtu	0.84
Henry Hub	Feb 2016	Natural Gas Futures	NYMEX	04/30/2012	4.409	$/MMBtu	0.85
Henry Hub	Mar 2016	Natural Gas Futures	NYMEX	04/30/2012	4.329	$/MMBtu	0.86
Henry Hub	Apr 2016	Natural Gas Futures	NYMEX	04/30/2012	4.119	$/MMBtu	0.91
Henry Hub	May 2016	Natural Gas Futures	NYMEX	04/30/2012	4.133	$/MMBtu	0.90
Henry Hub	Jun 2016	Natural Gas Futures	NYMEX	04/30/2012	4.158	$/MMBtu	0.90
Henry Hub	Jul 2016	Natural Gas Futures	NYMEX	04/30/2012	4.193	$/MMBtu	0.89
Henry Hub	Aug 2016	Natural Gas Futures	NYMEX	04/30/2012	4.211	$/MMBtu	0.89
Henry Hub	Sep 2016	Natural Gas Futures	NYMEX	04/30/2012	4.215	$/MMBtu	0.89
Henry Hub	Oct 2016	Natural Gas Futures	NYMEX	04/30/2012	4.251	$/MMBtu	0.88
Henry Hub	Nov 2016	Natural Gas Futures	NYMEX	04/30/2012	4.341	$/MMBtu	0.86

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Henry Hub	Dec 2016	Natural Gas Futures NYMEX	04/30/2012	4.531 $/MMBtu	0.82
Henry Hub	Jan 2017	Natural Gas Futures NYMEX	04/30/2012	4.626 $/MMBtu	0.81
Henry Hub	Feb 2017	Natural Gas Futures NYMEX	04/30/2012	4.598 $/MMBtu	0.81
Henry Hub	Mar 2017	Natural Gas Futures NYMEX	04/30/2012	4.518 $/MMBtu	0.83
Henry Hub	Apr 2017	Natural Gas Futures NYMEX	04/30/2012	4.313 $/MMBtu	0.87
Henry Hub	May 2017	Natural Gas Futures NYMEX	04/30/2012	4.323 $/MMBtu	0.86
Henry Hub	Jun 2017	Natural Gas Futures NYMEX	04/30/2012	4.348 $/MMBtu	0.86
Henry Hub	Jul 2017	Natural Gas Futures NYMEX	04/30/2012	4.383 $/MMBtu	0.85
Henry Hub	Aug 2017	Natural Gas Futures NYMEX	04/30/2012	4.405 $/MMBtu	0.85
Henry Hub	Sep 2017	Natural Gas Futures NYMEX	04/30/2012	4.409 $/MMBtu	0.85
Henry Hub	Oct 2017	Natural Gas Futures NYMEX	04/30/2012	4.445 $/MMBtu	0.84
Henry Hub	Nov 2017	Natural Gas Futures NYMEX	04/30/2012	4.535 $/MMBtu	0.82
Henry Hub	Dec 2017	Natural Gas Futures NYMEX	04/30/2012	4.725 $/MMBtu	0.79
Henry Hub	Jan 2018	Natural Gas Futures NYMEX	04/30/2012	4.820 $/MMBtu	0.77
Henry Hub	Feb 2018	Natural Gas Futures NYMEX	04/30/2012	4.793 $/MMBtu	0.78
Henry Hub	Mar 2018	Natural Gas Futures NYMEX	04/30/2012	4.715 $/MMBtu	0.79
Henry Hub	Apr 2018	Natural Gas Futures NYMEX	04/30/2012	4.488 $/MMBtu	0.90
Henry Hub	May 2018	Natural Gas Futures NYMEX	04/30/2012	4.498 $/MMBtu	0.90
Henry Hub	Jun 2018	Natural Gas Futures NYMEX	04/30/2012	4.523 $/MMBtu	0.89
Henry Hub	Jul 2018	Natural Gas Futures NYMEX	04/30/2012	4.558 $/MMBtu	0.89
Henry Hub	Aug 2018	Natural Gas Futures NYMEX	04/30/2012	4.583 $/MMBtu	0.88
Henry Hub	Sep 2018	Natural Gas Futures NYMEX	04/30/2012	4.590 $/MMBtu	0.88
Henry Hub	Oct 2018	Natural Gas Futures NYMEX	04/30/2012	4.628 $/MMBtu	0.87
Henry Hub	Nov 2018	Natural Gas Futures NYMEX	04/30/2012	4.723 $/MMBtu	0.85
Henry Hub	Dec 2018	Natural Gas Futures NYMEX	04/30/2012	4.918 $/MMBtu	0.82
Henry Hub	Jan 2019	Natural Gas Futures NYMEX	04/30/2012	5.018 $/MMBtu	0.80
Henry Hub	Feb 2019	Natural Gas Futures NYMEX	04/30/2012	4.991 $/MMBtu	0.81
Henry Hub	Mar 2019	Natural Gas Futures NYMEX	04/30/2012	4.913 $/MMBtu	-
Henry Hub	Apr 2019	Natural Gas Futures NYMEX	04/30/2012	4.683 $/MMBtu	0.86
Henry Hub	May 2019	Natural Gas Futures NYMEX	04/30/2012	4.693 $/MMBtu	0.86
Henry Hub	Jun 2019	Natural Gas Futures NYMEX	04/30/2012	4.718 $/MMBtu	0.86
Henry Hub	Jul 2019	Natural Gas Futures NYMEX	04/30/2012	4.753 $/MMBtu	0.85
Henry Hub	Aug 2019	Natural Gas Futures NYMEX	04/30/2012	4.778 $/MMBtu	0.84
Henry Hub	Sep 2019	Natural Gas Futures NYMEX	04/30/2012	4.788 $/MMBtu	0.84
Henry Hub	Oct 2019	Natural Gas Futures NYMEX	04/30/2012	4.833 $/MMBtu	0.83
Henry Hub	Nov 2019	Natural Gas Futures NYMEX	04/30/2012	4.935 $/MMBtu	0.82
Henry Hub	Dec 2019	Natural Gas Futures NYMEX	04/30/2012	5.133 $/MMBtu	0.79
Henry Hub	Jan 2020	Natural Gas Futures NYMEX	04/30/2012	5.240 $/MMBtu	0.77
Henry Hub	Feb 2020	Natural Gas Futures NYMEX	04/30/2012	5.213 $/MMBtu	0.77
Henry Hub	Mar 2020	Natural Gas Futures NYMEX	04/30/2012	5.135 $/MMBtu	-
Henry Hub	Apr 2020	Natural Gas Futures NYMEX	04/30/2012	4.905 $/MMBtu	-0.31
Henry Hub	May 2020	Natural Gas Futures NYMEX	04/30/2012	4.915 $/MMBtu	0.00
Henry Hub	Jun 2020	Natural Gas Futures NYMEX	04/30/2012	4.940 $/MMBtu	0.00
Henry Hub	Jul 2020	Natural Gas Futures NYMEX	04/30/2012	4.975 $/MMBtu	0.00
Henry Hub	Aug 2020	Natural Gas Futures NYMEX	04/30/2012	5.002 $/MMBtu	0.00
Henry Hub	Sep 2020	Natural Gas Futures NYMEX	04/30/2012	5.012 $/MMBtu	0.80
Henry Hub	Oct 2020	Natural Gas Futures NYMEX	04/30/2012	5.062 $/MMBtu	0.80
Henry Hub	Nov 2020	Natural Gas Futures NYMEX	04/30/2012	5.174 $/MMBtu	0.78
Henry Hub	Dec 2020	Natural Gas Futures NYMEX	04/30/2012	5.380 $/MMBtu	-
Henry Hub	Jan 2021	Natural Gas Futures NYMEX	04/30/2012	5.495 $/MMBtu	-
Henry Hub	Feb 2021	Natural Gas Futures NYMEX	04/30/2012	5.468 $/MMBtu	-
Henry Hub	Mar 2021	Natural Gas Futures NYMEX	04/30/2012	5.390 $/MMBtu	-
Henry Hub	Apr 2021	Natural Gas Futures NYMEX	04/30/2012	5.135 $/MMBtu	-
Henry Hub	May 2021	Natural Gas Futures NYMEX	04/30/2012	5.145 $/MMBtu	-
Henry Hub	Jun 2021	Natural Gas Futures NYMEX	04/30/2012	5.170 $/MMBtu	-
Henry Hub	Jul 2021	Natural Gas Futures NYMEX	04/30/2012	5.205 $/MMBtu	-
Henry Hub	Aug 2021	Natural Gas Futures NYMEX	04/30/2012	5.237 $/MMBtu	-
Henry Hub	Sep 2021	Natural Gas Futures NYMEX	04/30/2012	5.247 $/MMBtu	-
Henry Hub	Oct 2021	Natural Gas Futures NYMEX	04/30/2012	5.299 $/MMBtu	-
Henry Hub	Nov 2021	Natural Gas Futures NYMEX	04/30/2012	5.419 $/MMBtu	-
Henry Hub	Dec 2021	Natural Gas Futures NYMEX	04/30/2012	5.634 $/MMBtu	-
Henry Hub	Jan 2022	Natural Gas Futures NYMEX	04/30/2012	5.757 $/MMBtu	0.70
Henry Hub	Feb 2022	Natural Gas Futures NYMEX	04/30/2012	5.730 $/MMBtu	-
Henry Hub	Mar 2022	Natural Gas Futures NYMEX	04/30/2012	5.652 $/MMBtu	0.71

Henry Hub

Henry Hub	Apr 2022	Natural Gas Futures NYMEX	04/30/2012	5.367 $/MMBtu	0.75
Henry Hub	May 2022	Natural Gas Futures NYMEX	04/30/2012	5.362 $/MMBtu	-
Henry Hub	Jun 2022	Natural Gas Futures NYMEX	04/30/2012	5.395 $/MMBtu	0.75
Henry Hub	Jul 2022	Natural Gas Futures NYMEX	04/30/2012	5.440 $/MMBtu	0.74
Henry Hub	Aug 2022	Natural Gas Futures NYMEX	04/30/2012	5.482 $/MMBtu	-
Henry Hub	Sep 2022	Natural Gas Futures NYMEX	04/30/2012	5.493 $/MMBtu	0.73
Henry Hub	Oct 2022	Natural Gas Futures NYMEX	04/30/2012	5.549 $/MMBtu	0.73
Henry Hub	Nov 2022	Natural Gas Futures NYMEX	04/30/2012	5.679 $/MMBtu	-
Henry Hub	Dec 2022	Natural Gas Futures NYMEX	04/30/2012	5.909 $/MMBtu	0.68
Henry Hub	Jan 2023	Natural Gas Futures NYMEX	04/30/2012	6.039 $/MMBtu	0.67
Henry Hub	Feb 2023	Natural Gas Futures NYMEX	04/30/2012	6.012 $/MMBtu	0.67
Henry Hub	Mar 2023	Natural Gas Futures NYMEX	04/30/2012	5.934 $/MMBtu	-
Henry Hub	Apr 2023	Natural Gas Futures NYMEX	04/30/2012	5.634 $/MMBtu	0.72
Henry Hub	May 2023	Natural Gas Futures NYMEX	04/30/2012	5.619 $/MMBtu	0.72
Henry Hub	Jun 2023	Natural Gas Futures NYMEX	04/30/2012	5.659 $/MMBtu	0.71
Henry Hub	Jul 2023	Natural Gas Futures NYMEX	04/30/2012	5.709 $/MMBtu	-
Henry Hub	Aug 2023	Natural Gas Futures NYMEX	04/30/2012	5.754 $/MMBtu	0.70
Henry Hub	Sep 2023	Natural Gas Futures NYMEX	04/30/2012	5.769 $/MMBtu	0.70
Henry Hub	Oct 2023	Natural Gas Futures NYMEX	04/30/2012	5.834 $/MMBtu	0.69
Henry Hub	Nov 2023	Natural Gas Futures NYMEX	04/30/2012	5.964 $/MMBtu	0.68
Henry Hub	Dec 2023	Natural Gas Futures NYMEX	04/30/2012	6.194 $/MMBtu	-

Hourly data is presented based on the hour beginning.
NYMEX and CME Clearport market data provided by DTN.

AECO Storage Hub, Empress, West Coast Sta. 2 Canadian natural gas prices are reported in C$/GJ. U.S. natural gas locations are reported in US$/MMBtu.
Alberta and Ontario Canadian power prices are reported in C$/MWh. U.S. power locations are reported in US$/MWh.

PRELIMINARY

Big Sandy 2 UD Analysis Under FTCA_CSAPR Commodity Pricing
Capacity Resource Optimization
Expansion Plan Summary

	Retrofit 15 yr book life 30 Year Operating Life	***Retrofit 15_15 Yr life*** 15 Year Operating Life	***BS1 Repower 20 yr book life*** 30 Year Operating Life	***NGCC Replacement*** 30 Book/30 Operating	***Market to 2025***	***Market Only***
2011					0 MW- ICAP	0 MW- ICAP
2012					0 MW- ICAP	0 MW- ICAP
2013					0 MW- ICAP	0 MW- ICAP
2014					45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire			Big Sandy 1 Retire	225 MW- ICAP	225 MW- ICAP
2016	**Big Sandy 2 Retrofit**	**Big Sandy 1 Retire** **Big Sandy 2 Retrofit**	**Big Sandy 1 Retire** **1 -780 MW Repower,**	**1 -904 MW NGCC**	938 MW- ICAP	938 MW- ICAP
2017					922 MW- ICAP	922 MW- ICAP
2018					930 MW- ICAP	930 MW- ICAP
2019					934 MW- ICAP	934 MW- ICAP
2020					938 MW- ICAP	938 MW- ICAP
2021					939 MW- ICAP	939 MW- ICAP
2022					951 MW- ICAP	951 MW- ICAP
2023					957 MW- ICAP	957 MW- ICAP
2024					967 MW- ICAP	967 MW- ICAP
2025	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,** **904 MW NGCC**	1- 985 MW- ICAP
2026						
2027						
2028						
2029						
2030						
2031						
2032		**1 -578 MW CC,**				
2033						
2034						
2035						
2036						
2037						
2038						
2039						
2040						

	Retrofit 15 yr book life	*Retrofit 15_15 Yr life*	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2025*	*Market Only*
FTCA_CSAPR						
CPW	6,724,489	6,899,989	7,079,239	7,152,559	6,463,515	5,754,024
ICAP Revenue	(114,391)	(141,068)	(11,944)	77,262	(234,884)	(846,673)
Total	$6,838,879	$7,041,056	$7,091,182	$7,075,297	$6,698,399	$6,600,696
Cost Over Retrofit		$202,177	$252,303	$236,418	($140,480)	($238,183)

DRAFT

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607	2015	(225)	1,507
2016	165,006	(48,054)	(85,222)	298,281	147,762	76,499	224,261	522,542	2,302	524,845	(96,221)	621,065	1,576,526	147,762	2016	(938)	1,973
2017	236,355	(53,834)	28,377	261,812	147,762	137,403	285,165	546,977	1,511	548,488	(15,275)	563,763	1,919,419	147,762	2017	(178)	1,652
2018	254,318	(54,857)	51,107	258,068	147,762	149,018	296,780	554,848	626	555,473	(13,781)	569,255	2,238,116	147,762	2018	(189)	1,403
2019	242,101	(56,908)	22,817	276,191	147,762	139,475	287,237	563,428	572	564,000	(16,129)	580,129	2,537,072	147,762	2019	(197)	1,572
2020	257,391	(58,754)	50,028	266,118	155,093	140,061	295,154	561,271	0	561,271	(18,970)	580,242	2,812,305	155,093	2020	(206)	1,774
2021	263,061	(72,859)	57,490	278,430	155,093	143,776	298,869	577,298	0	577,298	(21,002)	598,301	3,073,534	155,093	2021	(206)	1,960
2022	252,602	(73,893)	44,072	282,423	155,093	143,739	298,832	581,255	108,290	689,545	(24,128)	713,673	3,360,356	155,093	2022	(218)	2,129
2023	225,510	(72,531)	(27,181)	325,222	155,093	140,117	295,210	620,431	96,073	716,505	(26,606)	743,111	3,635,257	155,093	2023	(224)	2,280
2024	255,531	(77,447)	21,273	311,705	155,093	150,129	305,222	616,927	106,998	723,925	(29,365)	753,290	3,891,762	155,093	2024	(234)	2,412
2025	336,073	(60,870)	136,139	260,804	257,945	166,903	424,848	685,653	116,552	802,205	20,285	781,919	4,136,841	257,945	2025	155	2,524
2026	354,700	(61,862)	156,979	259,583	257,945	176,504	434,449	694,032	122,595	816,627	19,255	797,372	4,366,887	257,945	2026	142	2,615
2027	351,082	(62,861)	134,514	279,429	257,945	174,827	432,772	712,201	119,821	832,023	17,955	814,067	4,583,071	257,945	2027	129	2,685
2028	370,369	(63,743)	156,602	277,510	257,945	184,827	442,772	720,282	125,870	846,152	16,731	829,421	4,785,815	257,945	2028	118	2,731
2029	370,732	(65,061)	141,804	293,989	257,945	188,259	446,204	740,193	124,788	864,981	15,461	849,520	4,976,958	257,945	2029	108	2,751
2030	367,888	(64,315)	118,179	314,024	257,945	184,860	442,805	756,829	121,007	877,836	13,734	864,102	5,155,920	257,945	2030	96	2,745
2031	388,156	(66,853)	144,828	310,181	146,766	148,849	295,615	605,796	128,489	734,285	11,814	722,471	5,293,649	146,766	2031	82	2,765
2032	406,168	(67,107)	169,892	303,383	146,766	150,067	296,833	600,216	135,793	736,009	10,491	725,518	5,420,959	146,766	2032	72	2,785
2033	411,019	(68,442)	163,642	315,819	146,766	149,262	296,028	611,847	136,812	748,659	7,036	741,623	5,540,746	146,766	2033	48	2,805
2034	394,818	(69,438)	110,425	353,831	146,766	143,959	290,725	644,557	127,901	772,458	6,134	766,323	5,654,678	146,766	2034	42	2,825
2035	408,588	(72,741)	122,805	358,523	146,766	155,220	301,986	660,509	133,275	793,784	5,012	788,772	5,762,622	146,766	2035	34	2,845
2036	413,597	(74,000)	120,432	367,165	146,766	157,203	303,969	671,134	135,608	806,742	3,438	803,304	5,863,812	146,766	2036	23	2,866
2037	426,893	(74,708)	132,956	368,645	146,766	158,887	305,653	674,298	141,194	815,492	868	814,624	5,958,266	146,766	2037	6	2,887
2038	423,004	(77,575)	107,009	393,570	146,766	160,400	307,166	700,736	139,015	839,751	(1,085)	840,837	6,048,007	146,766	2038	(7)	2,907
2039	432,896	(78,143)	113,529	397,511	146,766	163,017	309,783	707,294	143,353	850,646	(2,903)	853,549	6,131,859	146,766	2039	(19)	2,928
2040	431,457	(80,190)	89,506	422,142	146,766	342,266	489,032	911,174	141,291	1,052,464	(2,592)	1,055,057	6,227,265	146,766	2040	(17)	2,949
2011 Net Present Value																	
Period of 2011-2040	3,169,734	(585,636)	700,340	3,055,030	1,257,570	1,078,614	2,336,184	5,391,214	721,660	6,112,874	(114,391)	6,227,265					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,947,799			6,724,489	(114,391)	6,838,879					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit

	SO2 Emissions Total East	NSR SO2 NSR Adjusted Total	NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,724	6,593	(43,131)	7,009	5,319	0.33
2015	9,351	39,399	6,593	(32,806)	7,369	3,884	0.28
2016	4,097	1,158	6,593	5,435	5,144	2,089	0.15
2017	4,430	2,062	6,593	4,531	6,999	2,755	0.27
2018	4,358	2,151	6,593	4,442	7,419	2,785	0.28
2019	3,557	2,034	6,593	4,559	6,938	2,433	0.26
2020	4,573	2,124	6,593	4,469	7,448	1,741	0.27
2021	4,372	2,129	6,593	4,464	7,451	1,742	0.27
2022	4,559	2,006	6,593	4,587	7,182	1,676	0.25
2023	4,269	1,748	6,593	4,845	6,288	1,467	0.22
2024	3,655	2,004	6,593	4,589	6,914	1,619	0.25
2025	4,550	1,890	6,593	4,703	7,436	1,662	0.24
2026	3,917	2,104	6,593	4,489	7,718	1,739	0.26
2027	4,558	1,892	6,593	4,701	7,450	1,664	0.24
2028	3,884	2,112	6,593	4,481	7,726	1,742	0.27
2029	4,401	2,104	6,593	4,489	7,562	1,707	0.26
2030	4,332	1,820	6,593	4,773	7,236	1,610	0.23
2031	3,536	2,109	6,593	4,484	7,585	1,711	0.26
2032	4,572	2,118	6,593	4,475	7,914	1,783	0.27
2033	4,374	2,106	6,593	4,487	7,870	1,774	0.26
2034	4,558	1,807	6,593	4,786	7,263	1,618	0.23
2035	4,270	2,085	6,593	4,508	7,471	1,691	0.26
2036	3,658	2,082	6,593	4,511	7,504	1,701	0.26
2037	4,559	2,063	6,593	4,530	7,712	1,746	0.26
2038	3,917	2,052	6,593	4,541	7,495	1,701	0.26
2039	4,558	2,044	6,593	4,549	7,630	1,732	0.26
2040	3,886	2,035	6,593	4,558	7,423	1,688	0.26

	Summary of Energy Purchases and Sales (Gwh) Internal Requirement	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	677	6,894	301,823	660,209	9.6	11.9%
2015	7,479	139	23	(116)	260	1,242	982	6,903	310,633	640,453	9.3	8.0%
2016	7,488	139	19	(120)	2,373	743	(1,630)	6,911	313,409	934,474	13.5	14.6%
2017	7,505	139	28	(111)	307	855	548	6,927	321,132	884,895	12.8	11.0%
2018	7,536	139	37	(102)	154	1,139	985	6,955	332,128	901,382	13.0	9.6%
2019	7,571	139	36	(103)	341	772	431	6,988	337,451	917,580	13.1	8.5%
2020	7,604	139	34	(106)	174	1,132	958	7,019	340,282	920,523	13.1	7.5%
2021	7,648	288	34	(254)	151	1,223	1,072	7,059	347,477	945,778	13.4	7.0%
2022	7,695	288	34	(254)	354	1,044	690	7,102	349,845	1,063,518	15.0	7.4%
2023	7,744	288	34	(254)	828	450	(378)	7,148	360,647	1,103,758	15.4	7.0%
2024	7,798	289	34	(255)	384	702	318	7,198	365,998	1,119,289	15.6	6.5%
2025	7,846	288	34	(254)	185	1,775	1,591	7,242	368,701	1,150,621	15.9	6.2%
2026	7,896	288	34	(254)	140	1,990	1,851	7,288	377,102	1,174,474	16.1	5.9%
2027	7,947	288	34	(254)	299	1,832	1,533	7,335	387,215	1,201,282	16.4	5.6%
2028	7,999	289	34	(255)	167	1,930	1,764	7,383	389,382	1,218,803	16.5	5.3%
2029	8,044	288	34	(254)	202	1,720	1,519	7,425	399,077	1,248,597	16.8	5.1%
2030	8,093	288	34	(254)	515	1,712	1,197	7,470	406,645	1,270,747	17.0	4.9%
2031	8,143	288	34	(254)	212	1,683	1,472	7,516	414,203	1,136,674	15.1	4.1%
2032	8,195	289	34	(255)	134	1,888	1,754	7,564	421,901	1,147,419	15.2	3.9%
2033	8,241	288	34	(254)	187	1,829	1,642	7,606	429,743	1,171,366	15.4	3.8%
2034	8,289	288	34	(254)	474	1,447	973	7,651	437,730	1,204,053	15.7	3.7%
2035	8,339	288	34	(254)	287	1,349	1,061	7,697	445,866	1,234,637	16.0	3.6%
2036	8,389	289	34	(255)	319	1,317	999	7,743	454,153	1,257,457	16.2	3.5%
2037	8,439	288	34	(254)	273	1,410	1,138	7,789	462,594	1,277,218	16.4	3.4%
2038	8,488	288	34	(254)	307	1,123	816	7,835	471,191	1,312,028	16.7	3.4%
2039	8,538	288	34	(254)	299	1,169	871	7,881	479,949	1,333,498	16.9	3.3%
2040	8,589	289	34	(255)	443	1,020	577	7,927	488,869	1,543,926	19.5	3.7%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373	1 -737 MW Retrofit,	0	373	-69.3%
2017	1,198	1,116		0	1,116	-6.8%
2018	1,207	1,115		0	1,115	-7.6%
2019	1,218	1,119		0	1,119	-8.2%
2020	1,224	1,117		0	1,117	-8.8%
2021	1,238	1,131		0	1,131	-8.6%
2022	1,249	1,131		0	1,131	-9.4%
2023	1,255	1,131		0	1,131	-9.8%
2024	1,264	1,131		0	1,131	-10.5%
2025	1,281	1,131	1- 407 MW CC,	407	1,538	20.1%
2026	1,293	1,131		407	1,538	19.0%
2027	1,305	1,131		407	1,538	17.9%
2028	1,315	1,131		407	1,538	17.0%
2029	1,324	1,131		407	1,538	16.2%
2030	1,335	1,131		407	1,538	15.2%
2031	1,348	1,131		407	1,538	14.1%
2032	1,357	1,131		407	1,538	13.4%
2033	1,372	1,123		407	1,530	11.6%
2034	1,378	1,123		407	1,530	11.1%
2035	1,389	1,127		407	1,534	10.5%
2036	1,399	1,127		407	1,534	9.7%
2037	1,415	1,127		407	1,534	8.4%
2038	1,427	1,127		407	1,534	7.5%
2039	1,438	1,127		407	1,534	6.7%
2040	1,436	1,127		407	1,534	6.9%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions
[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Avoided Costs 2009-12

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit 15 year booklife 15 year operating life

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607	2015	(225)	1,507
2016	165,006	(48,054)	(85,222)	298,281	147,762	76,499	224,261	522,542	2,302	524,845	(96,221)	621,065	1,576,526	147,762	2016	(938)	1,973
2017	236,355	(53,834)	28,377	261,812	147,762	137,403	285,165	546,977	1,511	548,488	(15,275)	563,763	1,919,419	147,762	2017	(178)	1,652
2018	254,318	(54,857)	51,107	258,068	147,762	149,018	296,780	554,848	626	555,473	(13,781)	569,255	2,238,116	147,762	2018	(189)	1,403
2019	242,101	(56,908)	22,817	276,191	147,762	139,475	287,237	563,428	572	564,000	(16,129)	580,129	2,537,072	147,762	2019	(197)	1,572
2020	257,391	(58,754)	50,028	266,118	155,093	140,061	295,154	561,271	0	561,271	(18,970)	580,242	2,812,305	155,093	2020	(206)	1,774
2021	263,061	(72,859)	57,490	278,430	155,093	143,776	298,869	577,298	0	577,298	(21,002)	598,301	3,073,534	155,093	2021	(206)	1,960
2022	252,602	(73,893)	44,072	282,423	155,093	143,739	298,832	581,255	108,290	689,545	(24,128)	713,673	3,360,356	155,093	2022	(218)	2,129
2023	225,510	(72,531)	(27,181)	325,222	155,093	140,117	295,210	620,431	96,073	716,505	(26,606)	743,111	3,635,257	155,093	2023	(224)	2,280
2024	255,531	(77,447)	21,273	311,705	155,093	150,129	305,222	616,927	106,998	723,925	(29,365)	753,290	3,891,762	155,093	2024	(234)	2,412
2025	336,073	(60,870)	136,139	260,804	257,945	166,903	424,848	685,653	116,552	802,205	20,285	781,919	4,136,841	257,945	2025	155	2,524
2026	354,700	(61,862)	156,979	259,583	257,945	176,504	434,449	694,032	122,595	816,627	19,255	797,372	4,366,887	257,945	2026	142	2,615
2027	351,082	(62,861)	134,514	279,429	257,945	174,827	432,772	712,201	119,821	832,023	17,955	814,067	4,583,071	257,945	2027	129	2,685
2028	370,369	(63,743)	156,602	277,510	257,945	184,827	442,772	720,282	125,870	846,152	16,731	829,421	4,785,815	257,945	2028	118	2,731
2029	370,732	(65,061)	141,804	293,989	257,945	188,259	446,204	740,193	124,788	864,981	15,461	849,520	4,976,958	257,945	2029	108	2,751
2030	367,888	(64,315)	118,179	314,024	257,945	184,860	442,805	756,829	121,007	877,836	13,734	864,102	5,155,920	257,945	2030	96	2,745
2031	297,309	(63,037)	(89,683)	450,028	146,766	77,114	223,880	673,908	87,504	761,412	11,814	749,598	5,298,820	146,766	2031	82	2,765
2032	440,602	(68,345)	62,755	446,192	309,163	56,185	365,348	811,540	81,763	893,303	(11,943)	905,247	5,457,668	309,163	2032	(82)	2,785
2033	447,273	(69,414)	55,820	460,868	309,163	57,416	366,579	827,447	82,533	909,980	(15,560)	925,540	5,607,161	309,163	2033	(107)	2,805
2034	447,051	(70,888)	43,390	474,549	309,163	58,231	367,394	841,943	82,779	924,722	(16,624)	941,346	5,747,115	309,163	2034	(113)	2,825
2035	454,296	(72,637)	20,338	506,595	309,163	60,412	369,575	876,169	79,102	955,272	(17,910)	973,182	5,880,295	309,163	2035	(121)	2,845
2036	461,313	(74,583)	17,841	518,054	309,163	61,609	370,772	888,826	80,909	969,735	(19,649)	989,385	6,004,925	309,163	2036	(132)	2,866
2037	471,550	(75,139)	26,551	520,138	309,163	62,525	371,688	891,826	85,981	977,807	(22,386)	1,000,193	6,120,896	309,163	2037	(149)	2,887
2038	476,551	(76,731)	7,426	545,856	309,163	64,240	373,403	919,258	84,219	1,003,477	(24,507)	1,027,984	6,230,610	309,163	2038	(162)	2,907
2039	478,951	(77,191)	2,962	553,181	309,163	64,888	374,051	927,231	87,245	1,014,476	(26,493)	1,040,969	6,332,875	309,163	2039	(174)	2,928
2040	488,818	(78,080)	(12,681)	579,580	309,163	67,044	376,207	955,787	85,763	1,041,550	(26,352)	1,067,902	6,429,442	309,163	2040	(172)	2,949
2011 Net Present Value																	
Period of 2011-2040	3,204,949	(585,233)	539,438	3,250,744	1,445,922	939,905	2,385,827	5,636,571	651,803	6,288,374	(141,068)	6,429,442					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,997,442			6,899,989	(141,068)	7,041,056					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit 15 year booklife 15 year operating life

	SO2 Emissions Total East	NSR Adjusted Total [B]	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,724	6,593	(43,131)	7,009	5,319	0.33
2015	9,351	39,399	6,593	(32,806)	7,369	3,884	0.28
2016	4,097	1,158	6,593	5,435	5,144	2,089	0.15
2017	4,430	2,062	6,593	4,531	6,999	2,755	0.27
2018	4,358	2,151	6,593	4,442	7,419	2,785	0.28
2019	3,557	2,034	6,593	4,559	6,938	2,433	0.26
2020	4,573	2,124	6,593	4,469	7,448	1,741	0.27
2021	4,372	2,129	6,593	4,464	7,451	1,742	0.27
2022	4,559	2,006	6,593	4,587	7,182	1,676	0.25
2023	4,269	1,748	6,593	4,845	6,288	1,467	0.22
2024	3,655	2,004	6,593	4,589	6,914	1,619	0.25
2025	4,559	1,890	6,593	4,703	7,436	1,662	0.24
2026	3,917	2,104	6,593	4,489	7,718	1,739	0.26
2027	4,558	1,892	6,593	4,701	7,450	1,664	0.24
2028	3,884	2,112	6,593	4,481	7,726	1,742	0.27
2029	4,401	2,104	6,593	4,489	7,562	1,707	0.26
2030	4,332	1,820	6,593	4,773	7,236	1,610	0.23
2031	3,536	911	6,593	5,682	5,166	1,088	0.12
2032	4,572	0	6,593	6,593	4,765	787	0.00
2033	4,374	0	6,593	6,593	4,748	784	0.00
2034	4,558	0	6,593	6,593	4,701	780	0.00
2035	4,270	0	6,593	6,593	4,434	715	0.00
2036	3,658	0	6,593	6,593	4,477	727	0.00
2037	4,559	0	6,593	6,593	4,696	779	0.00
2038	3,917	0	6,593	6,593	4,541	744	0.00
2039	4,558	0	6,593	6,593	4,644	773	0.00
2040	3,886	0	6,593	6,593	4,506	739	0.00

	Summary of Energy Purchases and Sales (Gwh) Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,864	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	677	6,894	301,823	660,209	9.6	11.9%
2015	7,479	139	23	(116)	260	1,242	982	6,903	310,633	640,453	9.3	8.0%
2016	7,488	139	19	(120)	2,373	743	(1,630)	6,911	313,409	934,474	13.5	14.6%
2017	7,505	139	28	(111)	307	855	548	6,927	321,132	884,895	12.8	11.0%
2018	7,536	139	37	(102)	154	1,139	985	6,955	332,128	901,382	13.0	9.6%
2019	7,571	139	36	(103)	341	772	431	6,988	337,451	917,580	13.1	8.5%
2020	7,604	139	34	(106)	174	1,132	958	7,019	340,282	920,523	13.1	7.5%
2021	7,648	288	34	(254)	151	1,223	1,072	7,059	347,477	945,778	13.4	7.0%
2022	7,695	288	34	(254)	354	1,044	690	7,102	349,845	1,063,518	15.0	7.4%
2023	7,744	288	34	(254)	828	450	(378)	7,148	360,647	1,103,758	15.4	7.0%
2024	7,798	289	34	(255)	384	702	318	7,198	365,998	1,119,289	15.6	6.5%
2025	7,846	288	34	(254)	185	1,775	1,591	7,242	368,701	1,150,621	15.9	6.2%
2026	7,896	288	34	(254)	140	1,990	1,851	7,288	377,102	1,174,474	16.1	5.9%
2027	7,947	288	34	(254)	299	1,832	1,533	7,335	387,215	1,201,282	16.4	5.6%
2028	7,999	289	34	(255)	167	1,930	1,764	7,383	389,382	1,218,803	16.5	5.3%
2029	8,044	288	34	(254)	202	1,720	1,519	7,425	399,077	1,248,597	16.8	5.1%
2030	8,093	288	34	(254)	515	1,712	1,197	7,470	406,645	1,270,747	17.0	4.9%
2031	8,143	288	34	(254)	1,503	524	(979)	7,516	414,203	1,163,801	15.5	4.2%
2032	8,195	289	34	(255)	405	957	552	7,564	421,901	1,327,148	17.5	4.6%
2033	8,241	288	34	(254)	408	872	464	7,606	429,743	1,355,282	17.8	4.5%
2034	8,289	288	34	(254)	512	802	289	7,651	437,730	1,379,076	18.0	4.3%
2035	8,339	288	34	(254)	576	617	41	7,697	445,866	1,419,048	18.4	4.2%
2036	8,389	289	34	(255)	588	590	1	7,743	454,153	1,443,537	18.6	4.1%
2037	8,439	288	34	(254)	535	639	104	7,789	462,594	1,462,786	18.8	4.0%
2038	8,488	288	34	(254)	598	502	(97)	7,835	471,191	1,499,175	19.1	3.9%
2039	8,538	288	34	(254)	665	511	(154)	7,881	479,949	1,520,918	19.3	3.8%
2040	8,589	289	34	(255)	717	418	(300)	7,927	488,869	1,556,772	19.6	3.7%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373	1 -737 MW Retrofit,	0	373	-69.3%
2017	1,198	1,116		0	1,116	-6.8%
2018	1,207	1,115		0	1,115	-7.6%
2019	1,218	1,119		0	1,119	-8.2%
2020	1,224	1,117		0	1,117	-8.8%
2021	1,238	1,131		0	1,131	-8.6%
2022	1,249	1,131		0	1,131	-9.4%
2023	1,255	1,131		0	1,131	-9.8%
2024	1,264	1,131		0	1,131	-10.5%
2025	1,281	1,131	1- 407 MW CC,	407	1,538	20.1%
2026	1,293	1,131		407	1,538	19.0%
2027	1,305	1,131		407	1,538	17.9%
2028	1,315	1,131		407	1,538	17.0%
2029	1,324	1,131		407	1,538	16.2%
2030	1,335	1,131		407	1,538	15.2%
2031	1,348	1,131		407	1,538	14.1%
2032	1,357	399	1 -578 MW CC,	985	1,384	2.0%
2033	1,372	391		985	1,376	0.3%
2034	1,378	391		985	1,376	-0.2%
2035	1,389	395		985	1,380	-0.7%
2036	1,399	395		985	1,380	-1.4%
2037	1,415	395		985	1,380	-2.5%
2038	1,427	395		985	1,380	-3.3%
2039	1,438	395		985	1,380	-4.1%
2040	1,436	395		985	1,380	-3.9%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions
[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Avoided Costs 2000-12

DRAFT

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 1 Repower 20_30

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Market Value of Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures		Surplus	ICAP Value
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)		MW	$/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	(0)	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	306,568	(45,520)	93,574	258,514	607	45,523	46,130	304,643	35,151	339,794	2,451	337,344	1,171,545	607	2015	31	1,507
2016	261,948	(47,806)	(10,420)	320,174	216,791	33,267	250,058	570,233	1,727	571,960	(16,179)	588,139	1,560,171	216,791	2016	(158)	1,973
2017	261,110	(46,021)	(24,759)	331,889	216,791	42,248	259,039	590,929	981	591,910	(12,240)	604,150	1,927,627	216,791	2017	(142)	1,652
2018	272,816	(46,171)	(15,680)	334,666	216,791	43,056	259,847	594,513	397	594,910	(10,916)	605,827	2,266,799	216,791	2018	(150)	1,403
2019	271,831	(45,831)	(30,291)	347,953	216,791	44,128	260,919	608,872	356	609,227	(12,596)	621,823	2,587,241	216,791	2019	(154)	1,572
2020	277,705	(46,875)	(15,282)	339,862	224,122	45,120	269,242	609,104	0	609,104	(14,619)	623,723	2,883,100	224,122	2020	(158)	1,774
2021	285,928	(61,526)	(10,484)	357,937	224,122	46,127	270,249	628,186	0	628,186	(16,195)	644,381	3,164,449	224,122	2021	(159)	1,960
2022	297,847	(62,966)	(11,911)	372,725	224,122	47,357	271,479	644,204	65,479	709,683	(18,906)	728,589	3,457,265	224,122	2022	(171)	2,129
2023	295,719	(62,635)	(39,828)	398,181	224,122	48,408	272,530	670,711	61,326	732,038	(21,014)	753,052	3,735,844	224,122	2023	(177)	2,280
2024	308,264	(63,573)	(36,796)	408,633	224,122	49,648	273,770	682,402	63,294	745,696	(23,450)	769,146	3,997,748	224,122	2024	(187)	2,412
2025	393,703	(58,312)	99,655	352,361	326,974	67,359	394,333	746,694	75,377	822,071	26,475	795,596	4,247,113	326,974	2025	202	2,524
2026	410,118	(59,436)	100,540	369,015	326,974	70,140	397,114	766,128	75,338	841,466	25,668	815,798	4,482,475	326,974	2026	189	2,615
2027	417,943	(60,004)	104,034	373,913	326,974	71,257	398,231	772,144	78,308	850,452	24,539	825,913	4,701,805	326,974	2027	176	2,685
2028	429,257	(61,112)	97,556	392,812	326,974	73,527	400,501	793,313	77,225	870,538	23,428	847,110	4,908,873	326,974	2028	165	2,731
2029	436,546	(62,691)	86,970	412,267	326,974	75,375	402,349	814,616	76,259	890,875	22,206	868,668	5,104,325	326,974	2029	155	2,751
2030	446,505	(62,816)	99,848	409,473	326,974	76,846	403,820	813,293	80,663	893,956	20,466	873,489	5,285,230	326,974	2030	143	2,745
2031	455,572	(64,317)	89,830	430,060	326,974	79,413	406,387	836,446	78,857	915,303	18,594	896,709	5,456,175	326,974	2031	129	2,765
2032	466,718	(64,710)	107,526	423,902	326,974	80,720	407,694	831,596	84,626	916,221	17,320	898,901	5,613,910	326,974	2032	120	2,785
2033	473,614	(66,050)	103,064	436,600	326,974	82,426	409,400	846,000	85,546	931,546	13,915	917,631	5,762,125	326,974	2033	95	2,805
2034	483,685	(67,499)	102,033	449,151	326,974	84,412	411,386	860,537	86,876	947,413	13,062	934,351	5,901,039	326,974	2034	89	2,825
2035	483,601	(69,616)	74,349	478,868	326,974	86,694	413,668	892,537	82,550	975,087	11,990	963,097	6,032,839	326,974	2035	81	2,845
2036	491,883	(71,173)	75,349	487,707	146,766	88,252	235,018	722,724	84,625	807,349	10,466	796,883	6,133,220	146,766	2036	70	2,866
2037	500,999	(71,342)	83,539	488,802	146,766	89,390	236,156	724,957	89,675	814,632	7,947	806,685	6,226,754	146,766	2037	53	2,887
2038	499,784	(73,241)	61,040	511,985	146,766	91,072	237,838	749,823	87,425	837,248	6,044	831,204	6,315,467	146,766	2038	40	2,907
2039	509,032	(74,284)	65,129	518,187	146,766	92,618	239,384	757,571	91,212	848,783	4,278	844,505	6,398,430	146,766	2039	28	2,928
2040	511,478	(76,024)	46,326	541,176	146,766	124,803	271,569	812,746	89,166	901,912	4,640	897,272	6,479,568	146,766	2040	30	2,949
2011 Net Present Value																	
Period of 2011-2040	3,574,130	(535,075)	449,472	3,659,732	1,812,173	452,326	2,264,499	5,924,232	543,392	6,467,624	(11,944)	6,479,568					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,876,114			7,079,239	(11,944)	7,091,182					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions Total East	NSR Adjusted Total [B]	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,724	6,593	(43,131)	7,009	5,319	0.33
2015	9,351	45,764	6,593	(39,171)	8,110	6,039	0.32
2016	4,097	0	6,593	6,593	4,176	1,635	0.01
2017	4,430	0	6,593	6,593	4,028	1,812	0.01
2018	4,358	0	6,593	6,593	4,244	1,793	0.01
2019	3,557	0	6,593	6,593	4,026	1,505	0.01
2020	4,573	0	6,593	6,593	4,338	764	0.00
2021	4,372	0	6,593	6,593	4,327	762	0.00
2022	4,559	0	6,593	6,593	4,342	764	0.00
2023	4,269	0	6,593	6,593	4,014	694	0.00
2024	3,655	0	6,593	6,593	4,090	709	0.00
2025	4,559	0	6,593	6,593	4,809	808	0.00
2026	3,917	0	6,593	6,593	4,743	783	0.00
2027	4,558	0	6,593	6,593	4,869	814	0.00
2028	3,884	0	6,593	6,593	4,740	781	0.00
2029	4,401	0	6,593	6,593	4,621	754	0.00
2030	4,332	0	6,593	6,593	4,824	800	0.00
2031	3,536	0	6,593	6,593	4,655	758	0.00
2032	4,572	0	6,593	6,593	4,932	822	0.00
2033	4,374	0	6,593	6,593	4,921	820	0.00
2034	4,558	0	6,593	6,593	4,934	822	0.00
2035	4,270	0	6,593	6,593	4,627	754	0.00
2036	3,658	0	6,593	6,593	4,683	767	0.00
2037	4,559	0	6,593	6,593	4,898	819	0.00
2038	3,917	0	6,593	6,593	4,714	781	0.00
2039	4,558	0	6,593	6,593	4,855	814	0.00
2040	3,886	0	6,593	6,593	4,685	777	0.00

	Summary of Energy Purchases and Sales (Gwh)										TOTAL RATE IMPACT	
	Internal Requirement	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	(cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	677	6,894	301,823	660,209	9.6	11.9%
2015	7,479	139	23	(116)	139	1,927	1,788	6,903	310,633	647,977	9.4	8.3%
2016	7,488	139	19	(120)	621	368	(253)	6,911	313,409	901,548	13.0	13.8%
2017	7,505	139	28	(111)	766	284	(482)	6,927	321,132	925,281	13.4	11.8%
2018	7,536	139	37	(102)	622	319	(303)	6,955	332,128	937,954	13.5	10.2%
2019	7,571	139	36	(103)	843	279	(565)	6,988	337,451	959,275	13.7	9.1%
2020	7,604	139	34	(106)	612	346	(267)	7,019	340,282	964,005	13.7	8.1%
2021	7,648	288	34	(254)	569	393	(176)	7,059	347,477	991,858	14.1	7.5%
2022	7,695	288	34	(254)	559	390	(169)	7,102	349,845	1,078,434	15.2	7.5%
2023	7,744	288	34	(254)	855	268	(586)	7,148	360,647	1,113,699	15.6	7.1%
2024	7,798	289	34	(255)	807	278	(529)	7,198	365,998	1,135,144	15.8	6.7%
2025	7,846	288	34	(254)	421	1,408	986	7,242	368,701	1,164,297	16.1	6.3%
2026	7,896	288	34	(254)	346	1,384	1,038	7,288	377,102	1,192,899	16.4	6.0%
2027	7,947	288	34	(254)	390	1,439	1,049	7,335	387,215	1,213,128	16.5	5.7%
2028	7,999	289	34	(255)	390	1,336	946	7,383	389,382	1,236,491	16.7	5.4%
2029	8,044	288	34	(254)	424	1,223	800	7,425	399,077	1,267,746	17.1	5.2%
2030	8,093	288	34	(254)	409	1,338	928	7,470	406,645	1,280,134	17.1	5.0%
2031	8,143	288	34	(254)	461	1,259	798	7,516	414,203	1,310,911	17.4	4.8%
2032	8,195	289	34	(255)	425	1,397	972	7,564	421,901	1,320,802	17.5	4.6%
2033	8,241	288	34	(254)	402	1,307	904	7,606	429,743	1,347,374	17.7	4.4%
2034	8,289	288	34	(254)	364	1,250	887	7,651	437,730	1,372,081	17.9	4.3%
2035	8,339	288	34	(254)	497	1,038	541	7,697	445,866	1,408,962	18.3	4.2%
2036	8,389	289	34	(255)	478	1,009	531	7,743	454,153	1,251,036	16.2	3.5%
2037	8,439	288	34	(254)	402	1,024	622	7,789	462,594	1,269,278	16.3	3.4%
2038	8,488	288	34	(254)	512	859	347	7,835	471,191	1,302,395	16.6	3.4%
2039	8,538	288	34	(254)	470	864	394	7,881	479,949	1,324,454	16.8	3.3%
2040	8,589	289	34	(255)	572	743	171	7,927	488,869	1,386,141	17.5	3.3%

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,364		0	1,364	10.6%
2016	1,213	1,153	1 -780 MW Repower,	0	1,153	-5.0%
2017	1,198	1,152		0	1,152	-3.9%
2018	1,207	1,154		0	1,154	-4.4%
2019	1,218	1,162		0	1,162	-4.6%
2020	1,224	1,164		0	1,164	-4.9%
2021	1,238	1,179		0	1,179	-4.8%
2022	1,249	1,179		0	1,179	-5.6%
2023	1,255	1,179		0	1,179	-6.1%
2024	1,264	1,179		0	1,179	-6.8%
2025	1,281	1,179	1- 407 MW CC,	407	1,586	23.8%
2026	1,293	1,179		407	1,586	22.6%
2027	1,305	1,179		407	1,586	21.5%
2028	1,315	1,179		407	1,586	20.6%
2029	1,324	1,179		407	1,586	19.8%
2030	1,335	1,179		407	1,586	18.8%
2031	1,348	1,179		407	1,586	17.6%
2032	1,357	1,179		407	1,586	16.9%
2033	1,372	1,171		407	1,578	15.0%
2034	1,378	1,171		407	1,578	14.5%
2035	1,389	1,175		407	1,582	13.9%
2036	1,399	1,175		407	1,582	13.1%
2037	1,415	1,175		407	1,582	11.8%
2038	1,427	1,175		407	1,582	10.8%
2039	1,438	1,175		407	1,582	10.0%
2040	1,436	1,175		407	1,582	10.1%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions
[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Avoided Costs 2009-12

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FTCA CSAPR Commodity Pricing

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	(0)	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	275,723	(51,088)	45,062	281,748	607	1	608	282,356	29,797	312,153	(17,667)	329,819	1,166,144	607	2015	(225)	1,507
2016	265,889	(48,190)	(5,161)	319,241	219,322	33,361	252,683	571,924	1,730	573,654	(3,454)	577,108	1,547,481	219,322	2016	(34)	1,973
2017	264,881	(46,427)	(19,759)	331,067	219,322	42,256	261,578	592,645	983	593,628	(1,589)	595,217	1,909,504	219,322	2017	(18)	1,652
2018	276,542	(46,694)	(10,689)	333,925	219,322	42,920	262,242	596,167	398	596,565	(1,871)	598,436	2,244,539	219,322	2018	(26)	1,403
2019	275,802	(46,745)	(24,712)	347,259	219,322	43,738	263,060	610,319	356	610,676	(2,460)	613,136	2,560,503	219,322	2019	(30)	1,572
2020	281,618	(47,538)	(9,953)	339,109	226,653	44,543	271,196	610,304	0	610,304	(3,179)	613,483	2,851,504	226,653	2020	(34)	1,774
2021	290,148	(62,012)	(5,000)	357,159	226,653	45,380	272,033	629,193	0	629,193	(3,555)	632,747	3,127,774	226,653	2021	(35)	1,960
2022	302,092	(63,388)	(5,857)	371,336	226,653	46,444	273,097	644,433	65,933	710,366	(5,177)	715,543	3,415,347	226,653	2022	(47)	2,129
2023	300,374	(63,334)	(33,065)	396,774	226,653	47,320	273,973	670,747	61,817	732,564	(6,312)	738,877	3,688,682	226,653	2023	(53)	2,280
2024	313,032	(64,305)	(29,869)	407,206	226,653	48,351	275,004	682,210	63,787	745,997	(7,897)	753,894	3,945,392	226,653	2024	(63)	2,412
2025	397,097	(58,035)	104,722	350,410	329,505	65,757	395,262	745,672	75,723	821,395	42,751	778,645	4,189,444	329,505	2025	326	2,524
2026	414,742	(59,125)	106,929	366,938	329,505	68,403	397,908	764,846	75,810	840,656	42,532	798,124	4,419,707	329,505	2026	313	2,615
2027	421,946	(59,730)	109,782	371,894	329,505	69,273	398,778	770,672	78,712	849,384	41,849	807,536	4,634,157	329,505	2027	300	2,685
2028	433,804	(60,821)	103,872	390,753	329,505	71,359	400,864	791,617	77,680	869,297	41,037	828,260	4,836,618	329,505	2028	289	2,731
2029	441,578	(62,380)	93,777	410,181	329,505	73,056	402,561	812,742	76,755	889,498	39,942	849,556	5,027,769	329,505	2029	279	2,751
2030	451,055	(62,446)	106,218	407,283	329,505	74,234	403,739	811,022	81,114	892,136	38,167	853,969	5,204,632	329,505	2030	267	2,745
2031	460,422	(63,997)	96,615	427,804	329,505	76,575	406,080	833,884	79,339	913,223	36,423	876,800	5,371,781	329,505	2031	253	2,765
2032	471,622	(64,319)	114,474	421,467	329,505	77,631	407,136	828,604	85,113	913,717	35,277	878,440	5,525,926	329,505	2032	244	2,785
2033	475,881	(65,655)	107,888	433,647	329,505	78,914	408,419	842,066	85,772	927,838	32,000	895,837	5,670,621	329,505	2033	219	2,805
2034	490,443	(67,175)	111,328	446,290	329,505	80,990	410,495	856,785	87,547	944,332	31,279	913,053	5,806,368	329,505	2034	213	2,825
2035	488,660	(69,177)	81,730	476,107	329,505	82,817	412,322	888,429	83,055	971,484	30,337	941,147	5,935,165	329,505	2035	205	2,845
2036	497,150	(70,743)	83,039	484,854	329,505	84,290	413,795	898,649	85,148	983,797	28,946	954,851	6,055,444	329,505	2036	194	2,866
2037	505,038	(70,949)	89,906	486,082	329,505	85,193	414,698	900,779	90,083	990,862	26,560	964,302	6,167,254	329,505	2037	177	2,887
2038	504,709	(72,900)	68,668	508,941	329,505	86,844	416,349	925,291	87,914	1,013,205	24,791	988,414	6,272,745	329,505	2038	164	2,907
2039	514,193	(73,770)	73,028	514,935	329,505	88,291	417,796	932,731	91,723	1,024,455	23,160	1,001,295	6,371,112	329,505	2039	152	2,928
2040	515,003	(75,518)	52,379	538,143	329,505	90,192	419,697	957,840	89,527	1,047,366	23,658	1,023,708	6,463,682	329,505	2040	154	2,949
2011 Net Present Value																	
Period of 2011-2040	3,582,748	(540,539)	457,930	3,665,357	1,927,380	406,823	2,334,203	5,999,560	541,384	6,540,944	77,262	6,463,682					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,945,818			7,152,559	77,262	7,075,297					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FTCA CSAPR Commodity Pricing

	SO2 Emissions Total East	NSR SO2 NSR Adjusted Total	NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,724	6,593	(43,131)	7,009	5,319	0.33
2015	9,351	39,402	6,593	(32,809)	7,370	3,884	0.28
2016	4,097	0	6,593	6,593	4,209	1,638	0.01
2017	4,430	0	6,593	6,593	4,059	1,815	0.01
2018	4,358	0	6,593	6,593	4,273	1,796	0.01
2019	3,557	0	6,593	6,593	4,056	1,508	0.01
2020	4,573	0	6,593	6,593	4,368	767	0.00
2021	4,372	0	6,593	6,593	4,358	765	0.00
2022	4,559	0	6,593	6,593	4,373	767	0.00
2023	4,269	0	6,593	6,593	4,046	697	0.00
2024	3,655	0	6,593	6,593	4,122	712	0.00
2025	4,559	0	6,593	6,593	4,831	810	0.00
2026	3,917	0	6,593	6,593	4,773	786	0.00
2027	4,558	0	6,593	6,593	4,894	817	0.00
2028	3,884	0	6,593	6,593	4,768	784	0.00
2029	4,401	0	6,593	6,593	4,652	757	0.00
2030	4,332	0	6,593	6,593	4,851	803	0.00
2031	3,536	0	6,593	6,593	4,684	761	0.00
2032	4,572	0	6,593	6,593	4,960	825	0.00
2033	4,374	0	6,593	6,593	4,934	821	0.00
2034	4,558	0	6,593	6,593	4,972	826	0.00
2035	4,270	0	6,593	6,593	4,656	757	0.00
2036	3,658	0	6,593	6,593	4,712	771	0.00
2037	4,559	0	6,593	6,593	4,920	821	0.00
2038	3,917	0	6,593	6,593	4,740	784	0.00
2039	4,558	0	6,593	6,593	4,882	817	0.00
2040	3,886	0	6,593	6,593	4,704	779	0.00

	Summary of Energy Purchases and Sales (Gwh) Internal Requirement	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	677	6,894	301,823	660,209	9.6	11.9%
2015	7,479	139	23	(116)	260	1,242	982	6,903	310,633	640,452	9.3	8.0%
2016	7,488	139	19	(120)	575	410	(165)	6,911	313,409	890,518	12.9	13.5%
2017	7,505	139	28	(111)	716	316	(400)	6,927	321,132	916,348	13.2	11.7%
2018	7,536	139	37	(102)	580	355	(225)	6,955	332,128	930,564	13.4	10.1%
2019	7,571	139	36	(103)	789	311	(478)	6,988	337,451	950,587	13.6	9.0%
2020	7,604	139	34	(106)	571	384	(187)	7,019	340,282	953,765	13.6	7.9%
2021	7,648	288	34	(254)	529	436	(93)	7,059	347,477	980,224	13.9	7.4%
2022	7,695	288	34	(254)	519	427	(91)	7,102	349,845	1,065,388	15.0	7.4%
2023	7,744	288	34	(254)	797	298	(499)	7,148	360,647	1,099,524	15.4	7.0%
2024	7,798	289	34	(255)	752	309	(443)	7,198	365,998	1,119,892	15.6	6.5%
2025	7,846	288	34	(254)	421	1,465	1,044	7,242	368,701	1,147,346	15.8	6.2%
2026	7,896	288	34	(254)	333	1,449	1,117	7,288	377,102	1,175,226	16.1	5.9%
2027	7,947	288	34	(254)	387	1,502	1,116	7,335	387,215	1,194,751	16.3	5.6%
2028	7,999	289	34	(255)	378	1,398	1,020	7,383	389,382	1,217,642	16.5	5.3%
2029	8,044	288	34	(254)	407	1,286	879	7,425	399,077	1,248,633	16.8	5.1%
2030	8,093	288	34	(254)	402	1,401	999	7,470	406,645	1,260,614	16.9	4.9%
2031	8,143	288	34	(254)	447	1,319	872	7,516	414,203	1,291,003	17.2	4.7%
2032	8,195	289	34	(255)	414	1,460	1,047	7,564	421,901	1,300,341	17.2	4.5%
2033	8,241	288	34	(254)	419	1,359	940	7,606	429,743	1,325,580	17.4	4.4%
2034	8,289	288	34	(254)	345	1,334	989	7,651	437,730	1,350,783	17.7	4.2%
2035	8,339	288	34	(254)	484	1,099	615	7,697	445,866	1,387,012	18.0	4.1%
2036	8,389	289	34	(255)	466	1,072	606	7,743	454,153	1,409,004	18.2	4.0%
2037	8,439	288	34	(254)	400	1,078	678	7,789	462,594	1,426,896	18.3	3.9%
2038	8,488	288	34	(254)	499	915	416	7,835	471,191	1,459,605	18.6	3.8%
2039	8,538	288	34	(254)	457	920	464	7,881	479,949	1,481,244	18.8	3.7%
2040	8,589	289	34	(255)	567	785	218	7,927	488,869	1,512,578	19.1	3.6%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	1,277	1 -904 MW NGCC,	0	1,277	5.3%
2017	1,198	1,276		0	1,276	6.5%
2018	1,207	1,278		0	1,278	5.9%
2019	1,218	1,286		0	1,286	5.6%
2020	1,224	1,288		0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions
[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Avoided Costs 2009-12

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement FTCA CSAPR Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607	2015	(225)	1,507
2016	72,505	(39,933)	(262,595)	375,034	36,583	0	36,583	411,617	1,596	413,213	(96,221)	509,433	1,502,763	36,583	2016	(938)	1,973
2017	69,730	(38,322)	(276,013)	384,065	36,583	0	36,583	420,648	895	421,543	(79,238)	500,781	1,807,349	36,583	2017	(922)	1,652
2018	76,949	(37,921)	(270,260)	385,130	36,583	0	36,583	421,713	359	422,072	(67,811)	489,883	2,081,610	36,583	2018	(930)	1,403
2019	71,023	(38,178)	(290,487)	399,689	36,583	0	36,583	436,272	317	436,589	(76,355)	512,944	2,345,943	36,583	2019	(934)	1,572
2020	75,257	(38,014)	(279,386)	392,657	43,914	0	43,914	436,571	0	436,571	(86,584)	523,156	2,594,098	43,914	2020	(938)	1,774
2021	76,468	(52,948)	(279,891)	409,307	43,914	0	43,914	453,221	0	453,221	(95,706)	548,927	2,833,769	43,914	2021	(939)	1,960
2022	76,760	(53,230)	(327,351)	457,341	43,914	0	43,914	501,255	41,846	543,102	(105,268)	648,370	3,094,346	43,914	2022	(951)	2,129
2023	69,002	(53,442)	(360,111)	482,555	43,914	0	43,914	526,469	37,415	563,884	(113,496)	677,380	3,344,931	43,914	2023	(957)	2,280
2024	72,372	(55,536)	(367,599)	495,506	43,914	0	43,914	539,420	38,892	578,313	(121,283)	699,595	3,583,152	43,914	2024	(967)	2,412
2025	81,642	(55,412)	(361,955)	499,009	43,914	0	43,914	542,923	43,499	586,421	(129,327)	715,748	3,807,491	43,914	2025	(985)	2,524
2026	78,048	(57,716)	(379,843)	515,607	43,914	0	43,914	559,521	41,408	600,930	(135,760)	736,690	4,020,030	43,914	2026	(998)	2,615
2027	84,784	(57,284)	(380,130)	522,199	43,914	0	43,914	566,113	44,620	610,733	(141,167)	751,900	4,219,705	43,914	2027	(1,011)	2,685
2028	80,991	(57,681)	(404,862)	543,534	43,914	0	43,914	587,448	42,317	629,765	(145,139)	774,904	4,409,123	43,914	2028	(1,022)	2,731
2029	78,423	(58,015)	(427,619)	564,057	43,914	0	43,914	607,971	40,691	648,662	(147,575)	796,237	4,588,277	43,914	2029	(1,032)	2,751
2030	87,541	(59,668)	(421,887)	569,096	43,914	0	43,914	613,010	45,003	658,013	(148,981)	806,994	4,755,411	43,914	2030	(1,044)	2,745
2031	81,748	(61,063)	(452,898)	595,709	43,914	0	43,914	639,623	41,777	681,400	(152,073)	833,473	4,914,301	43,914	2031	(1,058)	2,765
2032	93,974	(61,736)	(440,654)	596,364	43,914	0	43,914	640,278	47,748	688,026	(154,577)	842,603	5,062,157	43,914	2032	(1,067)	2,785
2033	95,736	(60,574)	(458,091)	614,401	43,914	0	43,914	658,315	48,243	706,558	(159,220)	865,779	5,201,997	43,914	2033	(1,092)	2,805
2034	97,730	(60,581)	(475,043)	633,355	43,914	0	43,914	677,269	48,860	726,128	(161,319)	887,448	5,333,938	43,914	2034	(1,098)	2,825
2035	88,055	(61,315)	(520,192)	669,562	43,914	0	43,914	713,476	43,703	757,179	(163,648)	920,827	5,459,953	43,914	2035	(1,106)	2,845
2036	91,936	(62,216)	(532,274)	686,425	43,914	0	43,914	730,339	45,436	775,775	(166,436)	942,211	5,578,641	43,914	2036	(1,117)	2,866
2037	103,500	(62,847)	(528,007)	694,354	43,914	0	43,914	738,268	50,811	789,078	(170,230)	959,308	5,689,871	43,914	2037	(1,134)	2,887
2038	99,098	(63,655)	(561,317)	724,070	43,914	0	43,914	767,984	48,344	816,328	(173,416)	989,743	5,795,504	43,914	2038	(1,147)	2,907
2039	107,502	(63,288)	(568,402)	739,192	43,914	0	43,914	783,106	52,131	835,238	(176,474)	1,011,712	5,894,894	43,914	2039	(1,159)	2,928
2040	102,561	(64,152)	(604,085)	770,798	43,914	0	43,914	814,712	49,460	864,172	(177,414)	1,041,586	5,989,082	43,914	2040	(1,157)	2,949
2011 Net Present Value																	
Period of 2011-2040	1,609,713	(488,474)	(2,333,106)	4,431,292	302,627	0	302,627	4,733,919	408,490	5,142,409	(846,673)	5,989,082					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							914,241			5,754,024	(846,673)	6,600,696					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement FTCA CSAPR Commodity Pricing

	SO2 Emissions Total East	NSR Adjusted Total B	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,724	6,593	(43,131)	7,009	5,319	0.33
2015	9,351	39,399	6,593	(32,806)	7,369	3,884	0.28
2016	4,097	0	6,593	6,593	2,600	1,465	0.01
2017	4,430	0	6,593	6,593	2,470	1,644	0.01
2018	4,358	0	6,593	6,593	2,695	1,627	0.01
2019	3,557	0	6,593	6,593	2,470	1,337	0.01
2020	4,573	0	6,593	6,593	2,783	597	0.00
2021	4,372	0	6,593	6,593	2,775	595	0.00
2022	4,559	0	6,593	6,593	2,775	595	0.00
2023	4,269	0	6,593	6,593	2,449	525	0.00
2024	3,655	0	6,593	6,593	2,513	539	0.00
2025	4,559	0	6,593	6,593	2,775	595	0.00
2026	3,917	0	6,593	6,593	2,607	559	0.00
2027	4,558	0	6,593	6,593	2,774	595	0.00
2028	3,884	0	6,593	6,593	2,597	557	0.00
2029	4,401	0	6,593	6,593	2,466	528	0.00
2030	4,332	0	6,593	6,593	2,691	577	0.00
2031	3,536	0	6,593	6,593	2,466	529	0.00
2032	4,572	0	6,593	6,593	2,783	596	0.00
2033	4,374	0	6,593	6,593	2,775	595	0.00
2034	4,558	0	6,593	6,593	2,775	595	0.00
2035	4,270	0	6,593	6,593	2,450	525	0.00
2036	3,658	0	6,593	6,593	2,514	539	0.00
2037	4,559	0	6,593	6,593	2,775	595	0.00
2038	3,917	0	6,593	6,593	2,607	559	0.00
2039	4,558	0	6,593	6,593	2,775	595	0.00
2040	3,886	0	6,593	6,593	2,599	557	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923	Est. Embedded Costs	Grand Total	TOTAL RATE IMPACT	
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	GWh	(G/T/D)	(ALL COSTS)	(cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	677	6,894	301,823	660,209	9.6	11.9%
2015	7,479	139	23	(116)	260	1,242	982	6,903	310,633	640,453	9.3	8.0%
2016	7,488	139	19	(120)	4,621		(4,621)	6,911	313,409	822,842	11.9	11.8%
2017	7,505	139	28	(111)	4,778		(4,778)	6,927	321,132	821,912	11.9	9.6%
2018	7,536	139	37	(102)	4,579		(4,579)	6,955	332,128	822,011	11.8	8.2%
2019	7,571	139	36	(103)	4,855		(4,855)	6,988	337,451	850,395	12.2	7.5%
2020	7,604	139	34	(106)	4,566		(4,566)	7,019	340,282	863,437	12.3	6.8%
2021	7,648	288	34	(254)	4,458		(4,458)	7,059	347,477	896,404	12.7	6.4%
2022	7,695	288	34	(254)	4,495		(4,495)	7,102	349,845	998,215	14.1	6.8%
2023	7,744	288	34	(254)	4,902		(4,902)	7,148	360,647	1,038,027	14.5	6.5%
2024	7,798	289	34	(255)	4,870		(4,870)	7,198	365,998	1,065,594	14.8	6.1%
2025	7,846	288	34	(254)	4,646		(4,646)	7,242	368,701	1,084,449	15.0	5.8%
2026	7,896	288	34	(254)	4,859		(4,859)	7,288	377,102	1,113,792	15.3	5.5%
2027	7,947	288	34	(254)	4,737		(4,737)	7,335	387,215	1,139,115	15.5	5.3%
2028	7,999	289	34	(255)	4,980		(4,980)	7,383	389,382	1,164,286	15.8	5.0%
2029	8,044	288	34	(254)	5,165		(5,165)	7,425	399,077	1,195,314	16.1	4.9%
2030	8,093	288	34	(254)	4,965		(4,965)	7,470	406,645	1,213,639	16.2	4.7%
2031	8,143	288	34	(254)	5,252		(5,252)	7,516	414,203	1,247,676	16.6	4.5%
2032	8,195	289	34	(255)	4,966		(4,966)	7,564	421,901	1,264,504	16.7	4.4%
2033	8,241	288	34	(254)	5,041		(5,041)	7,606	429,743	1,295,521	17.0	4.2%
2034	8,289	288	34	(254)	5,103		(5,103)	7,651	437,730	1,325,178	17.3	4.1%
2035	8,339	288	34	(254)	5,514		(5,514)	7,697	445,866	1,366,692	17.8	4.1%
2036	8,389	289	34	(255)	5,507		(5,507)	7,743	454,153	1,396,364	18.0	4.0%
2037	8,439	288	34	(254)	5,297		(5,297)	7,789	462,594	1,421,901	18.3	3.9%
2038	8,488	288	34	(254)	5,536		(5,536)	7,835	471,191	1,460,935	18.6	3.8%
2039	8,538	288	34	(254)	5,436		(5,436)	7,881	479,949	1,491,661	18.9	3.7%
2040	8,589	289	34	(255)	5,683		(5,683)	7,927	488,869	1,530,456	19.3	3.6%

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	399		0	399	-68.9%
2026	1,293	399		0	399	-69.2%
2027	1,305	399		0	399	-69.5%
2028	1,315	399		0	399	-69.7%
2029	1,324	399		0	399	-69.9%
2030	1,335	399		0	399	-70.1%
2031	1,348	399		0	399	-70.4%
2032	1,357	399		0	399	-70.6%
2033	1,372	391		0	391	-71.5%
2034	1,378	391		0	391	-71.7%
2035	1,389	395		0	395	-71.6%
2036	1,399	395		0	395	-71.8%
2037	1,415	395		0	395	-72.1%
2038	1,427	395		0	395	-72.3%
2039	1,438	395		0	395	-72.6%
2040	1,436	395		0	395	-72.5%

A Total East SO2 Excludes Cardinal 2&3 Emissions
B NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Avoided Costs 2009-12

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FTCA CSAPR Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607	2015	(225)	1,507
2016	72,505	(39,933)	(262,595)	375,034	36,583	0	36,583	411,617	1,596	413,213	(96,221)	509,433	1,502,763	36,583	2016	(938)	1,973
2017	69,730	(38,322)	(276,013)	384,065	36,583	0	36,583	420,648	895	421,543	(79,238)	500,781	1,807,349	36,583	2017	(922)	1,652
2018	76,949	(37,921)	(270,260)	385,130	36,583	0	36,583	421,713	359	422,072	(67,811)	489,883	2,081,610	36,583	2018	(930)	1,403
2019	71,023	(38,178)	(290,487)	399,689	36,583	0	36,583	436,272	317	436,589	(76,355)	512,944	2,345,943	36,583	2019	(934)	1,572
2020	75,257	(38,014)	(279,386)	392,657	43,914	0	43,914	436,571	0	436,571	(86,584)	523,156	2,594,098	43,914	2020	(938)	1,774
2021	76,468	(52,948)	(279,891)	409,307	43,914	0	43,914	453,221	0	453,221	(95,706)	548,927	2,833,769	43,914	2021	(939)	1,960
2022	76,760	(53,230)	(327,351)	457,341	43,914	0	43,914	501,255	41,846	543,102	(105,268)	648,370	3,094,346	43,914	2022	(951)	2,129
2023	69,002	(53,442)	(360,111)	482,555	43,914	0	43,914	526,469	37,415	563,884	(113,496)	677,380	3,344,931	43,914	2023	(957)	2,280
2024	72,372	(55,536)	(367,599)	495,506	43,914	0	43,914	539,420	38,892	578,313	(121,283)	699,595	3,583,152	43,914	2024	(967)	2,412
2025	433,917	(56,413)	156,711	333,619	356,636	71,982	428,618	762,237	79,464	841,702	64,862	776,840	3,826,639	356,636	2025	494	2,524
2026	454,347	(57,259)	161,383	350,224	356,636	74,946	431,582	781,805	79,839	861,644	65,441	796,203	4,056,348	356,636	2026	481	2,615
2027	462,813	(57,878)	166,023	354,668	356,636	76,034	432,670	787,338	82,826	870,164	65,365	804,799	4,270,071	356,636	2027	468	2,685
2028	475,076	(58,791)	160,361	373,507	356,636	78,230	434,866	808,373	81,801	890,173	64,960	825,213	4,471,787	356,636	2028	457	2,731
2029	484,538	(59,964)	151,904	392,597	356,636	80,152	436,788	829,386	81,010	910,396	64,037	846,359	4,662,218	356,636	2029	448	2,751
2030	494,314	(60,240)	165,823	388,731	356,636	81,511	438,147	826,878	85,398	912,276	62,215	850,062	4,838,272	356,636	2030	436	2,745
2031	505,594	(61,839)	159,080	408,353	356,636	84,136	440,772	849,125	83,817	932,942	60,643	872,299	5,004,563	356,636	2031	422	2,765
2032	516,656	(61,931)	177,696	400,891	356,636	85,335	441,971	842,862	89,574	932,436	59,672	872,764	5,157,712	356,636	2032	412	2,785
2033	520,376	(62,995)	170,954	412,417	356,636	86,707	443,343	855,760	90,180	945,941	56,571	889,370	5,301,362	356,636	2033	388	2,805
2034	539,528	(64,291)	179,868	423,951	356,636	89,306	445,942	869,893	92,405	962,298	56,027	906,272	5,436,102	356,636	2034	381	2,825
2035	537,833	(66,258)	151,124	452,967	356,636	91,280	447,916	900,883	87,915	988,798	55,264	933,535	5,563,856	356,636	2035	373	2,845
2036	545,481	(67,351)	151,936	460,896	356,636	92,810	449,446	910,342	89,933	1,000,275	54,051	946,223	5,683,049	356,636	2036	363	2,866
2037	555,920	(67,787)	162,927	460,779	356,636	94,115	450,751	911,530	95,101	1,006,631	51,846	954,785	5,793,755	356,636	2037	345	2,887
2038	554,677	(69,721)	141,607	482,791	356,636	95,843	452,479	935,270	92,845	1,028,116	50,260	977,856	5,898,119	356,636	2038	332	2,907
2039	565,263	(70,804)	148,372	487,695	356,636	97,563	454,199	941,894	96,758	1,038,651	48,812	989,839	5,995,361	356,636	2039	321	2,928
2040	565,104	(72,550)	127,788	509,866	356,636	99,546	456,182	966,048	94,468	1,060,516	49,495	1,011,021	6,086,784	356,636	2040	323	2,949
2011 Net Present Value																	
Period of 2011-2040	2,796,836	(494,808)	(585,150)	3,876,794	1,207,804	240,620	1,448,424	5,325,218	526,682	5,851,900	(234,884)	6,086,784					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,060,039			6,463,515	(234,884)	6,698,399					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FTCA CSAPR Commodity Pricing

	SO2 Emissions Total East	NSR Adjusted Total B	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,724	6,593	(43,131)	7,009	5,319	0.33
2015	9,351	39,399	6,593	(32,806)	7,369	3,884	0.28
2016	4,097	0	6,593	6,593	2,600	1,465	0.01
2017	4,430	0	6,593	6,593	2,470	1,644	0.01
2018	4,358	0	6,593	6,593	2,695	1,627	0.01
2019	3,557	0	6,593	6,593	2,470	1,337	0.01
2020	4,573	0	6,593	6,593	2,783	597	0.00
2021	4,372	0	6,593	6,593	2,775	595	0.00
2022	4,559	0	6,593	6,593	2,775	595	0.00
2023	4,269	0	6,593	6,593	2,449	525	0.00
2024	3,655	0	6,593	6,593	2,513	539	0.00
2025	4,559	0	6,593	6,593	5,070	836	0.00
2026	3,917	0	6,593	6,593	5,026	813	0.00
2027	4,558	0	6,593	6,593	5,150	844	0.00
2028	3,884	0	6,593	6,593	5,021	812	0.00
2029	4,401	0	6,593	6,593	4,909	785	0.00
2030	4,332	0	6,593	6,593	5,107	831	0.00
2031	3,536	0	6,593	6,593	4,948	790	0.00
2032	4,572	0	6,593	6,593	5,220	853	0.00
2033	4,374	0	6,593	6,593	5,188	849	0.00
2034	4,558	0	6,593	6,593	5,248	856	0.00
2035	4,270	0	6,593	6,593	4,928	786	0.00
2036	3,658	0	6,593	6,593	4,976	799	0.00
2037	4,559	0	6,593	6,593	5,195	851	0.00
2038	3,917	0	6,593	6,593	5,006	812	0.00
2039	4,558	0	6,593	6,593	5,150	846	0.00
2040	3,886	0	6,593	6,593	4,963	807	0.00

	Summary of Energy Purchases and Sales (Gwh) Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	677	6,894	301,823	660,209	9.6	11.9%
2015	7,479	139	23	(116)	260	1,242	982	6,903	310,633	640,453	9.3	8.0%
2016	7,488	139	19	(120)	4,621		(4,621)	6,911	313,409	822,842	11.9	11.8%
2017	7,505	139	28	(111)	4,778		(4,778)	6,927	321,132	821,912	11.9	9.6%
2018	7,536	139	37	(102)	4,579		(4,579)	6,955	332,128	822,011	11.8	8.2%
2019	7,571	139	36	(103)	4,855		(4,855)	6,988	337,451	850,395	12.2	7.5%
2020	7,604	139	34	(106)	4,566		(4,566)	7,019	340,282	863,437	12.3	6.8%
2021	7,648	288	34	(254)	4,458		(4,458)	7,059	347,477	896,404	12.7	6.4%
2022	7,695	288	34	(254)	4,495		(4,495)	7,102	349,845	998,215	14.1	6.8%
2023	7,744	288	34	(254)	4,902		(4,902)	7,148	360,647	1,038,027	14.5	6.5%
2024	7,798	289	34	(255)	4,870		(4,870)	7,198	365,998	1,065,594	14.8	6.1%
2025	7,846	288	34	(254)	332	2,009	1,676	7,242	368,701	1,145,541	15.8	6.2%
2026	7,896	288	34	(254)	245	2,030	1,786	7,288	377,102	1,173,304	16.1	5.9%
2027	7,947	288	34	(254)	293	2,088	1,795	7,335	387,215	1,192,014	16.3	5.6%
2028	7,999	289	34	(255)	290	1,974	1,684	7,383	389,382	1,214,595	16.5	5.3%
2029	8,044	288	34	(254)	292	1,848	1,556	7,425	399,077	1,245,436	16.8	5.1%
2030	8,093	288	34	(254)	308	1,980	1,672	7,470	406,645	1,256,706	16.8	4.9%
2031	8,143	288	34	(254)	318	1,889	1,571	7,516	414,203	1,286,501	17.1	4.7%
2032	8,195	289	34	(255)	315	2,047	1,732	7,564	421,901	1,294,665	17.1	4.5%
2033	8,241	288	34	(254)	318	1,922	1,604	7,606	429,743	1,319,112	17.3	4.3%
2034	8,289	288	34	(254)	225	1,941	1,716	7,651	437,730	1,344,002	17.6	4.2%
2035	8,339	288	34	(254)	332	1,665	1,333	7,697	445,866	1,379,401	17.9	4.1%
2036	8,389	289	34	(255)	322	1,622	1,300	7,743	454,153	1,400,376	18.1	4.0%
2037	8,439	288	34	(254)	247	1,645	1,398	7,789	462,594	1,417,379	18.2	3.8%
2038	8,488	288	34	(254)	326	1,441	1,115	7,835	471,191	1,449,048	18.5	3.8%
2039	8,538	288	34	(254)	276	1,447	1,171	7,881	479,949	1,469,789	18.7	3.7%
2040	8,589	289	34	(255)	370	1,271	901	7,927	488,869	1,499,890	18.9	3.6%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	1,471	1- 407 MW CC,1 -904 MW NGCC,	407	1,878	46.6%
2026	1,293	1,471		407	1,878	45.3%
2027	1,305	1,471		407	1,878	43.9%
2028	1,315	1,471		407	1,878	42.8%
2029	1,324	1,471		407	1,878	41.9%
2030	1,335	1,471		407	1,878	40.7%
2031	1,348	1,471		407	1,878	39.3%
2032	1,357	1,471		407	1,878	38.4%
2033	1,372	1,463		407	1,870	36.3%
2034	1,378	1,463		407	1,870	35.7%
2035	1,389	1,467		407	1,874	34.9%
2036	1,399	1,467		407	1,874	34.0%
2037	1,415	1,467		407	1,874	32.4%
2038	1,427	1,467		407	1,874	31.3%
2039	1,438	1,467		407	1,874	30.3%
2040	1,436	1,467		407	1,874	30.5%

A Total East SO2 Excludes Cardinal 2&3 Emissions

B NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary Under FT - CSAPR Pricing
NGCC Replacement - Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)	0	2011	0	958
2012	0	(0)	0	0	0	0	0	0	0	0	0	0	(0)	0	2012	0	388
2013	(0)	0	(0)	(0)	0	(0)	(0)	(0)	0	(0)	0	(0)	(0)	0	2013	0	161
2014	0	0	(0)	0	0	(0)	(0)	0	(0)	(0)	0	(0)	(0)	0	2014	0	595
2015	15	0	18	(3)	0	1	1	(2)	2	(0)	0	(0)	(0)	0	2015	0	1,507
2016	100,883	(137)	80,061	20,960	71,560	(43,138)	28,422	49,382	(572)	48,809	92,766	(43,957)	(29,046)	71,560	2016	904	1,973
2017	28,526	7,407	(48,136)	69,255	71,560	(95,147)	(23,587)	45,668	(528)	45,140	13,687	31,453	(9,915)	71,560	2017	159	1,652
2018	22,224	8,163	(61,795)	75,857	71,560	(106,097)	(34,537)	41,320	(228)	41,092	11,910	29,182	6,422	71,560	2018	163	1,403
2019	33,702	10,163	(47,529)	71,068	71,560	(95,737)	(24,177)	46,891	(216)	46,676	13,669	33,007	23,431	71,560	2019	167	1,572
2020	24,227	11,217	(59,981)	72,991	71,560	(95,518)	(23,958)	49,033	0	49,033	15,792	33,241	39,199	71,560	2020	171	1,774
2021	27,086	10,847	(62,490)	78,730	71,560	(98,395)	(26,835)	51,894	0	51,894	17,448	34,447	54,239	71,560	2021	171	1,960
2022	49,490	10,506	(49,929)	88,913	71,560	(97,295)	(25,735)	63,178	(42,357)	20,821	18,951	1,870	54,991	71,560	2022	171	2,129
2023	74,865	9,196	(5,884)	71,552	71,560	(92,796)	(21,236)	50,316	(34,256)	16,060	20,294	(4,234)	53,425	71,560	2023	171	2,280
2024	57,501	13,142	(51,142)	95,501	71,560	(101,778)	(30,218)	65,282	(43,211)	22,072	21,468	604	53,630	71,560	2024	171	2,412
2025	61,024	2,836	(31,417)	89,605	71,560	(101,146)	(29,586)	60,019	(40,829)	19,190	22,465	(3,275)	52,604	71,560	2025	171	2,524
2026	60,042	2,737	(50,050)	107,355	71,560	(108,101)	(36,541)	70,814	(46,786)	24,029	23,277	752	52,821	71,560	2026	171	2,615
2027	70,864	3,131	(24,732)	92,465	71,560	(105,554)	(33,994)	58,471	(41,109)	17,362	23,893	(6,531)	51,086	71,560	2027	171	2,685
2028	63,435	2,922	(52,730)	113,243	71,560	(113,468)	(41,908)	71,335	(48,189)	23,145	24,306	(1,161)	50,803	71,560	2028	171	2,731
2029	70,847	2,682	(48,027)	116,192	71,560	(115,203)	(43,643)	72,549	(48,033)	24,516	24,481	36	50,810	71,560	2029	171	2,751
2030	83,167	1,870	(11,961)	93,259	71,560	(110,626)	(39,066)	54,193	(39,893)	14,300	24,433	(10,133)	48,712	71,560	2030	171	2,745
2031	72,266	2,856	(48,213)	117,623	182,739	(72,274)	110,465	228,088	(49,150)	178,938	24,609	154,329	78,133	182,739	2031	171	2,740
2032	65,454	2,787	(55,418)	118,084	182,739	(72,435)	110,304	228,387	(50,680)	177,708	24,786	152,922	104,967	182,739	2032	171	2,734
2033	64,861	2,787	(55,753)	117,828	182,739	(70,348)	112,391	230,219	(51,041)	179,178	24,964	154,214	129,875	182,739	2033	171	2,729
2034	95,625	2,264	903	92,459	182,739	(62,969)	119,770	212,229	(40,354)	171,874	25,144	146,730	151,690	182,739	2034	171	2,724
2035	80,072	3,564	(41,075)	117,583	182,739	(72,402)	110,337	227,920	(50,220)	177,700	25,325	152,375	172,543	182,739	2035	171	2,718
2036	83,553	3,257	(37,393)	117,689	182,739	(72,913)	109,826	227,515	(50,460)	177,055	25,508	151,547	191,632	182,739	2036	171	2,713
2037	78,145	3,759	(43,050)	117,437	182,739	(73,694)	109,045	226,481	(51,112)	175,370	25,691	149,678	208,988	182,739	2037	171	2,708
2038	81,705	4,675	(38,342)	115,371	182,739	(73,556)	109,183	224,555	(51,101)	173,454	25,876	147,577	224,738	182,739	2038	171	2,702
2039	81,297	4,373	(40,501)	117,424	182,739	(74,726)	108,013	225,438	(51,629)	173,808	26,063	147,746	239,253	182,739	2039	171	2,697
2040	83,546	4,672	(37,127)	116,001	182,739	(252,074)	(69,335)	46,666	(51,764)	(5,098)	26,251	(31,348)	236,418	182,739	2040	171	2,692
2011 Net Present Value																	
Period of 2011-2040	413,014	45,097	(242,410)	610,326	669,811	(671,791)	(1,981)	608,346	(180,276)	428,070	191,652	236,418					
Base Case O&M 2011-2040							0			0	0	0					
Utility Cost Present Value 2011-2040							(1,981)			428,070	191,652	236,418					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FTCA CSAPR Commodity Pricing

	SO2 Emissions Total East	NSR SO2 NSR ljusted Tota	NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	0	0	0	0	0	0	0
2012	0	0	0	(0)	0	0	0
2013	(0)	(0)	0	0	(0)	(0)	0
2014	(0)	0	0	0	(0)	(0)	(0)
2015	0	3	0	(3)	0	0	0
2016	0	(1,158)	0	1,158	(935)	(450)	(0)
2017	0	(2,062)	0	2,062	(2,940)	(940)	(0)
2018	0	(2,151)	0	2,151	(3,146)	(989)	(0)
2019	0	(2,034)	0	2,034	(2,881)	(925)	(0)
2020	0	(2,124)	0	2,124	(3,080)	(974)	(0)
2021	0	(2,129)	0	2,129	(3,093)	(977)	(0)
2022	0	(2,006)	0	2,006	(2,809)	(909)	(0)
2023	0	(1,748)	0	1,748	(2,242)	(770)	(0)
2024	0	(2,004)	0	2,004	(2,792)	(907)	(0)
2025	0	(1,890)	0	1,890	(2,605)	(852)	(0)
2026	0	(2,104)	0	2,104	(2,945)	(953)	(0)
2027	0	(1,892)	0	1,892	(2,556)	(847)	(0)
2028	0	(2,112)	0	2,112	(2,958)	(957)	(0)
2029	0	(2,104)	0	2,104	(2,911)	(950)	(0)
2030	0	(1,820)	0	1,820	(2,386)	(807)	(0)
2031	0	(2,109)	0	2,109	(2,901)	(950)	(0)
2032	0	(2,118)	0	2,118	(2,954)	(958)	(0)
2033	0	(2,106)	0	2,106	(2,936)	(953)	(0)
2034	0	(1,807)	0	1,807	(2,292)	(792)	(0)
2035	0	(2,085)	0	2,085	(2,815)	(934)	(0)
2036	0	(2,082)	0	2,082	(2,792)	(930)	(0)
2037	0	(2,063)	0	2,063	(2,792)	(924)	(0)
2038	0	(2,052)	0	2,052	(2,755)	(918)	(0)
2039	0	(2,044)	0	2,044	(2,748)	(915)	(0)
2040	0	(2,035)	0	2,035	(2,720)	(909)	(0)

	Summary of Energy Purchases and Sales (Gwh) Internal Requiremen	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	CAGR (thru)
2011	0	0	0	0	0	0	0	0	0	(0)	(0)	0
2012	0	0	0	0	0	0	0	0	0	0	(0)	(0)
2013	0	0	0	0	0	(0)	(0)	0	0	(0)	(0)	0
2014	0	0	0	0	0	(0)	(0)	0	0	(0)	(0)	0
2015	0	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2016	0	0	0	0	(1,798)	(332)	1,466	0	0	(43,957)	(1)	(0)
2017	0	0	0	0	409	(539)	(948)	0	0	31,453	0	0
2018	(0)	0	0	0	426	(784)	(1,210)	(0)	0	29,182	0	0
2019	0	0	0	0	449	(461)	(909)	0	0	33,007	0	0
2020	0	0	0	0	397	(748)	(1,145)	0	0	33,241	0	0
2021	0	0	0	0	378	(787)	(1,165)	0	0	34,447	0	0
2022	0	0	0	0	164	(617)	(781)	0	0	1,870	0	0
2023	0	0	0	0	(31)	(152)	(121)	0	0	(4,234)	(0)	(0)
2024	0	0	0	0	368	(393)	(761)	0	0	604	0	0
2025	0	0	0	0	237	(310)	(547)	0	0	(3,275)	(0)	(0)
2026	(0)	0	0	0	193	(541)	(734)	(0)	0	752	0	0
2027	0	0	0	0	88	(330)	(418)	0	0	(6,531)	(0)	(0)
2028	0	0	0	0	212	(532)	(744)	0	0	(1,161)	(0)	(0)
2029	0	0	0	0	205	(435)	(640)	0	0	36	0	0
2030	(0)	0	0	0	(112)	(311)	(198)	(0)	0	(10,133)	(0)	(0)
2031	0	0	0	0	236	(364)	(600)	0	0	154,329	2	0
2032	(0)	0	0	0	279	(428)	(707)	(0)	0	152,922	2	0
2033	0	0	0	0	233	(469)	(702)	0	0	154,214	2	0
2034	0	0	0	0	(129)	(113)	16	0	0	146,730	2	0
2035	0	0	0	0	196	(250)	(446)	0	0	152,375	2	0
2036	(0)	0	0	0	147	(245)	(393)	(0)	0	151,547	2	0
2037	(0)	0	0	0	127	(333)	(460)	(0)	0	149,678	2	0
2038	(0)	0	0	0	192	(208)	(400)	(0)	0	147,577	2	0
2039	0	0	0	0	158	(249)	(407)	0	0	147,746	2	0
2040	(0)	0	0	0	124	(235)	(359)	(0)	0	(31,348)	(0)	(0)

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	0	0		0	0	0
2012	0	0		0	0	0
2013	0	0		0	0	0
2014	0	0		0	0	0
2015	0	0		0	0	0
2016	0	904	1 -904 MW NGCC,	0	904	1
2017	0	159		0	159	0
2018	0	163		0	163	0
2019	0	167		0	167	0
2020	0	171		0	171	0
2021	0	171		0	171	0
2022	0	171		0	171	0
2023	0	171		0	171	0
2024	0	171		0	171	0
2025	0	171	1- 407 MW CC,	0	171	0
2026	0	171		0	171	0
2027	0	171		0	171	0
2028	0	171		0	171	0
2029	0	171		0	171	0
2030	0	171		0	171	0
2031	0	171		0	171	0
2032	0	171		0	171	0
2033	0	171		0	171	0
2034	0	171		0	171	0
2035	0	171		0	171	0
2036	0	171		0	171	0
2037	0	171		0	171	0
2038	0	171		0	171	0
2039	0	171		0	171	0
2040	0	171		0	171	0

[A] Total East SO2 Excludes Cardinal 2&3 Emissions
[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

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KPCo Capacity Resource Optimization

Costs and Emissions Summary for FT - CSAPR Commodity Prices

Big Sandy 1 Repower - Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)	0	2011	0	958
2012	0	(0)	0	0	0	0	0	0	0	0	0	0	(0)	0	2012	0	388
2013	(0)	0	(0)	(0)	0	(0)	(0)	(0)	0	(0)	0	(0)	(0)	0	2013	0	161
2014	0	0	(0)	0	0	(0)	(0)	0	(0)	(0)	0	(0)	(0)	0	2014	0	595
2015	30,860	5,568	48,530	(23,237)	0	45,523	45,523	22,285	5,356	27,641	20,117	7,524	5,401	0	2015	257	1,507
2016	96,942	247	74,802	21,893	69,029	(43,232)	25,797	47,690	(575)	47,115	80,042	(32,926)	(16,356)	69,029	2016	780	1,973
2017	24,754	7,813	(53,136)	70,077	69,029	(95,155)	(26,126)	43,952	(530)	43,422	3,036	40,386	8,208	69,029	2017	35	1,652
2018	18,498	8,686	(66,787)	76,598	69,029	(105,962)	(36,933)	39,666	(229)	39,437	2,865	36,572	28,683	69,029	2018	39	1,403
2019	29,730	11,077	(53,108)	71,761	69,029	(95,347)	(26,318)	45,444	(216)	45,228	3,533	41,695	50,169	69,029	2019	43	1,572
2020	20,313	11,879	(65,310)	73,745	69,029	(94,941)	(25,912)	47,833	0	47,833	4,351	43,482	70,794	69,029	2020	47	1,774
2021	22,866	11,333	(67,974)	79,508	69,029	(97,649)	(28,620)	50,888	0	50,888	4,807	46,081	90,914	69,029	2021	47	1,960
2022	45,246	10,927	(55,983)	90,302	69,029	(96,382)	(27,353)	62,949	(42,811)	20,138	5,222	14,916	96,909	69,029	2022	47	2,129
2023	70,209	9,896	(12,646)	72,959	69,029	(91,708)	(22,679)	50,280	(34,747)	15,533	5,592	9,941	100,587	69,029	2023	47	2,280
2024	52,732	13,874	(58,069)	96,928	69,029	(100,482)	(31,453)	65,475	(43,704)	21,771	5,915	15,856	105,986	69,029	2024	47	2,412
2025	57,630	2,558	(36,484)	91,556	69,029	(99,544)	(30,515)	61,041	(41,175)	19,866	6,190	13,677	110,272	69,029	2025	47	2,524
2026	55,418	2,425	(56,439)	109,431	69,029	(106,364)	(37,335)	72,096	(47,257)	24,839	6,413	18,426	115,588	69,029	2026	47	2,615
2027	66,860	2,857	(30,480)	94,484	69,029	(103,570)	(34,541)	59,943	(41,514)	18,429	6,583	11,846	118,734	69,029	2027	47	2,685
2028	58,887	2,631	(59,046)	115,302	69,029	(111,301)	(42,272)	73,031	(48,645)	24,386	6,697	17,689	123,058	69,029	2028	47	2,731
2029	65,814	2,371	(54,834)	118,278	69,029	(112,884)	(43,855)	74,423	(48,529)	25,894	6,745	19,148	127,366	69,029	2029	47	2,751
2030	78,617	1,499	(18,331)	95,449	69,029	(108,014)	(38,985)	56,464	(40,344)	16,119	6,732	9,387	129,310	69,029	2030	47	2,745
2031	67,416	2,536	(54,998)	119,878	180,208	(69,436)	110,772	230,650	(49,632)	181,018	6,780	174,237	162,526	180,208	2031	47	2,740
2032	60,550	2,397	(62,365)	120,518	180,208	(69,347)	110,861	231,379	(51,167)	180,212	6,829	173,383	192,951	180,208	2032	47	2,734
2033	62,594	2,392	(60,578)	120,781	180,208	(66,835)	113,373	234,153	(51,267)	182,886	6,878	176,008	221,379	180,208	2033	47	2,729
2034	88,867	1,939	(8,392)	95,320	180,208	(59,547)	120,661	215,980	(41,025)	174,956	6,928	168,028	246,361	180,208	2034	47	2,724
2035	75,013	3,125	(48,456)	120,345	180,208	(68,526)	111,682	232,027	(50,725)	181,303	6,978	174,325	270,217	180,208	2035	47	2,718
2036	78,286	2,827	(45,083)	120,542	0	(68,951)	(68,951)	51,590	(50,983)	607	7,028	(6,421)	269,408	0	2036	47	2,713
2037	74,106	3,366	(49,417)	120,157	0	(69,497)	(69,497)	50,659	(51,520)	(860)	7,079	(7,939)	268,488	0	2037	47	2,708
2038	76,780	4,334	(45,969)	118,415	0	(69,328)	(69,328)	49,087	(51,590)	(2,503)	7,130	(9,633)	267,460	0	2038	47	2,702
2039	76,136	3,859	(48,400)	120,676	0	(70,398)	(70,398)	50,278	(52,141)	(1,863)	7,181	(9,044)	266,571	0	2039	47	2,697
2040	80,021	4,166	(43,180)	119,035	0	(217,463)	(217,463)	(98,428)	(52,124)	(150,552)	7,233	(157,785)	252,303	0	2040	47	2,692
2011 Net Present Value																	
Period of 2011-2040	404,396	50,562	(250,868)	604,702	554,603	(626,288)	(71,685)	533,017	(178,267)	354,750	102,447	252,303					
Base Case O&M 2011-2040							0			0	0	0					
Utility Cost Present Value 2011-2040							(71,685)			354,750	102,447	252,303					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions	NSR SO2			CO2 Emissions	NOX	HG (Tons)
	Total East	NSR Adjusted Total	NSR SO2 Caps.	NSR Surplus/(Deficit)	Total East	Total East	East
2011	0	0	0	0	0	0	0
2012	0	0	0	(0)	0	0	0
2013	(0)	(0)	0	0	(0)	(0)	0
2014	(0)	0	0	0	(0)	(0)	(0)
2015	0	6,366	0	(6,366)	741	2,155	0
2016	0	(1,158)	0	1,158	(968)	(454)	(0)
2017	0	(2,062)	0	2,062	(2,970)	(943)	(0)
2018	0	(2,151)	0	2,151	(3,175)	(992)	(0)
2019	0	(2,034)	0	2,034	(2,912)	(928)	(0)
2020	0	(2,124)	0	2,124	(3,110)	(977)	(0)
2021	0	(2,129)	0	2,129	(3,124)	(980)	(0)
2022	0	(2,006)	0	2,006	(2,839)	(912)	(0)
2023	0	(1,748)	0	1,748	(2,274)	(774)	(0)
2024	0	(2,004)	0	2,004	(2,824)	(910)	(0)
2025	0	(1,890)	0	1,890	(2,627)	(854)	(0)
2026	0	(2,104)	0	2,104	(2,975)	(957)	(0)
2027	0	(1,892)	0	1,892	(2,581)	(850)	(0)
2028	0	(2,112)	0	2,112	(2,986)	(960)	(0)
2029	0	(2,104)	0	2,104	(2,941)	(953)	(0)
2030	0	(1,820)	0	1,820	(2,413)	(810)	(0)
2031	0	(2,109)	0	2,109	(2,930)	(953)	(0)
2032	0	(2,118)	0	2,118	(2,982)	(962)	(0)
2033	0	(2,106)	0	2,106	(2,949)	(954)	(0)
2034	0	(1,807)	0	1,807	(2,330)	(796)	(0)
2035	0	(2,085)	0	2,085	(2,843)	(937)	(0)
2036	0	(2,082)	0	2,082	(2,821)	(933)	(0)
2037	0	(2,063)	0	2,063	(2,814)	(927)	(0)
2038	0	(2,052)	0	2,052	(2,782)	(920)	(0)
2039	0	(2,044)	0	2,044	(2,775)	(918)	(0)
2040	0	(2,035)	0	2,035	(2,738)	(911)	(0)

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923	Est. Embedded Costs	Grand Total	TOTAL RATE IMPACT	
	Internal Requirement	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	GWh	(G/T/D)	(ALL COSTS)	(cents / kWh)	CAGR (thru)
2011	0	0	0	0	0	0	0	0	0	(0)	(0)	0
2012	0	0	0	0	0	0	0	0	0	0	(0)	(0)
2013	0	0	0	0	0	(0)	(0)	0	0	(0)	(0)	0
2014	0	0	0	0	0	(0)	(0)	0	0	(0)	(0)	0
2015	0	0	0	0	(121)	685	806	0	0	7,524	0	0
2016	0	0	0	0	(1,752)	(375)	1,377	0	0	(32,926)	(0)	(0)
2017	(0)	0	0	0	459	(571)	(1,030)	(0)	0	40,386	1	0
2018	(0)	0	0	0	468	(820)	(1,288)	(0)	0	36,572	1	0
2019	0	0	0	0	503	(493)	(996)	0	0	41,695	1	0
2020	0	0	0	0	438	(787)	(1,225)	0	0	43,482	1	0
2021	(0)	0	0	0	418	(829)	(1,247)	(0)	0	46,081	1	0
2022	0	0	0	0	205	(654)	(859)	0	0	14,916	0	0
2023	0	0	0	0	27	(181)	(208)	0	0	9,941	0	0
2024	(0)	0	0	0	424	(424)	(847)	(0)	0	15,856	0	0
2025	0	0	0	0	236	(368)	(604)	0	0	13,677	0	0
2026	(0)	0	0	0	206	(607)	(813)	(0)	0	18,426	0	0
2027	(0)	0	0	0	91	(393)	(484)	(0)	0	11,846	0	0
2028	0	0	0	0	223	(594)	(817)	0	0	17,689	0	0
2029	0	0	0	0	222	(497)	(719)	0	0	19,148	0	0
2030	(0)	0	0	0	(105)	(374)	(268)	(0)	0	9,387	0	0
2031	0	0	0	0	249	(425)	(674)	0	0	174,237	2	0
2032	0	0	0	0	290	(492)	(782)	0	0	173,383	2	0
2033	(0)	0	0	0	215	(522)	(737)	(0)	0	176,008	2	0
2034	0	0	0	0	(110)	(197)	(86)	0	0	168,028	2	0
2035	0	0	0	0	209	(311)	(520)	0	0	174,325	2	0
2036	(0)	0	0	0	160	(308)	(468)	(0)	0	(6,421)	(0)	(0)
2037	(0)	0	0	0	129	(387)	(516)	(0)	0	(7,939)	(0)	(0)
2038	0	0	0	0	205	(263)	(469)	0	0	(9,633)	(0)	(0)
2039	0	0	0	0	172	(305)	(477)	0	0	(9,044)	(0)	(0)
2040	(0)	0	0	0	129	(277)	(406)	(0)	0	(157,785)	(2)	(0)

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	0	0		0	0	0
2012	0	0		0	0	0
2013	0	0		0	0	0
2014	0	0		0	0	0
2015	0	257		0	257	0
2016	0	780		0	780	1
2017	0	35		0	35	0
2018	0	39		0	39	0
2019	0	43		0	43	0
2020	0	47		0	47	0
2021	0	47		0	47	0
2022	0	47		0	47	0
2023	0	47		0	47	0
2024	0	47		0	47	0
2025	0	47		0	47	0
2026	0	47		0	47	0
2027	0	47		0	47	0
2028	0	47		0	47	0
2029	0	47		0	47	0
2030	0	47		0	47	0
2031	0	47		0	47	0
2032	0	47		0	47	0
2033	0	47		0	47	0
2034	0	47		0	47	0
2035	0	47		0	47	0
2036	0	47		0	47	0
2037	0	47		0	47	0
2038	0	47		0	47	0
2039	0	47		0	47	0
2040	0	47		0	47	0

[A] Total East SO2 Excludes Cardinal 2&3 Emissions

[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary Under FT - CSAPR Pricing
NGCC Replacement - Repower

	Optimal Plan Cost Summary ($000)				Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2011	0	958
2012	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2012	0	388
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2013	0	161
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	0	595
2015	(30,845)	(5,568)	(48,512)	23,234	0	(45,522)	(45,522)	(22,287)	(5,354)	(27,641)	(20,117)	(7,524)	(5,401)	0	2015	(257)	1,507
2016	3,941	(384)	5,259	(934)	2,531	94	2,625	1,691	3	1,694	12,725	(11,031)	(12,690)	2,531	2016	124	1,973
2017	3,772	(406)	5,000	(822)	2,531	8	2,539	1,716	2	1,718	10,651	(8,933)	(18,123)	2,531	2017	124	1,652
2018	3,726	(524)	4,991	(741)	2,531	(136)	2,395	1,654	1	1,655	9,045	(7,390)	(22,261)	2,531	2018	124	1,403
2019	3,972	(914)	5,580	(694)	2,531	(390)	2,141	1,447	1	1,448	10,136	(8,688)	(26,738)	2,531	2019	124	1,572
2020	3,914	(663)	5,330	(754)	2,531	(577)	1,954	1,200	0	1,200	11,441	(10,240)	(31,595)	2,531	2020	124	1,774
2021	4,220	(486)	5,484	(778)	2,531	(747)	1,784	1,006	0	1,006	12,640	(11,634)	(36,675)	2,531	2021	124	1,960
2022	4,244	(421)	6,054	(1,389)	2,531	(913)	1,618	229	454	683	13,729	(13,046)	(41,918)	2,531	2022	124	2,129
2023	4,656	(700)	6,762	(1,407)	2,531	(1,088)	1,443	36	491	527	14,702	(14,175)	(47,162)	2,531	2023	124	2,280
2024	4,769	(732)	6,927	(1,427)	2,531	(1,297)	1,234	(193)	493	301	15,553	(15,252)	(52,356)	2,531	2024	124	2,412
2025	3,394	278	5,067	(1,951)	2,531	(1,602)	929	(1,022)	346	(676)	16,275	(16,951)	(57,669)	2,531	2025	124	2,524
2026	4,624	311	6,389	(2,076)	2,531	(1,736)	795	(1,282)	471	(810)	16,863	(17,674)	(62,768)	2,531	2026	124	2,615
2027	4,003	274	5,748	(2,019)	2,531	(1,984)	547	(1,472)	404	(1,067)	17,310	(18,377)	(67,648)	2,531	2027	124	2,685
2028	4,548	291	6,316	(2,059)	2,531	(2,168)	363	(1,696)	456	(1,240)	17,609	(18,849)	(72,255)	2,531	2028	124	2,731
2029	5,032	311	6,807	(2,086)	2,531	(2,319)	212	(1,874)	497	(1,377)	17,736	(19,113)	(76,556)	2,531	2029	124	2,751
2030	4,550	370	6,370	(2,190)	2,531	(2,612)	(81)	(2,271)	452	(1,819)	17,701	(19,520)	(80,598)	2,531	2030	124	2,745
2031	4,849	320	6,785	(2,256)	2,531	(2,837)	(306)	(2,562)	482	(2,080)	17,828	(19,908)	(84,394)	2,531	2031	124	2,740
2032	4,904	391	6,947	(2,434)	2,531	(3,089)	(558)	(2,992)	487	(2,505)	17,957	(20,461)	(87,984)	2,531	2032	124	2,734
2033	2,267	395	4,825	(2,953)	2,531	(3,513)	(982)	(3,934)	226	(3,708)	18,086	(21,794)	(91,504)	2,531	2033	124	2,729
2034	6,758	324	9,295	(2,861)	2,531	(3,422)	(891)	(3,752)	671	(3,081)	18,216	(21,298)	(94,671)	2,531	2034	124	2,724
2035	5,059	439	7,382	(2,762)	2,531	(3,877)	(1,346)	(4,107)	505	(3,602)	18,347	(21,950)	(97,675)	2,531	2035	124	2,718
2036	5,267	430	7,690	(2,852)	182,739	(3,962)	178,777	175,925	523	176,448	18,480	157,968	(77,776)	182,739	2036	124	2,713
2037	4,039	393	6,367	(2,720)	182,739	(4,197)	178,542	175,822	408	176,230	18,613	157,618	(59,500)	182,739	2037	124	2,708
2038	4,925	341	7,627	(3,043)	182,739	(4,228)	178,511	175,468	489	175,957	18,747	157,210	(42,722)	182,739	2038	124	2,702
2039	5,161	514	7,900	(3,252)	182,739	(4,327)	178,412	175,160	512	175,672	18,882	156,790	(27,319)	182,739	2039	124	2,697
2040	3,525	506	6,053	(3,033)	182,739	(34,612)	148,127	145,094	360	145,454	19,018	126,437	(15,885)	182,739	2040	124	2,692
2011 Net Present Value																	
Period of 2011-2040	8,618	(5,464)	8,458	5,624	115,208	(45,503)	69,704	75,329	(2,008)	73,320	89,206	(15,885)					
Base Case O&M 2011-2040							0			0	0	0					
Utility Cost Present Value 2011-2040							69,704			73,320	89,206	(15,885)					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FTCA CSAPR Commodity Pricing

	SO2 Emissions Total East	NSR SO2 NSR Adjusted Total	NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	(6,362)	0	6,362	(741)	(2,155)	(0)
2016	0	0	0	0	33	3	0
2017	0	0	0	0	31	3	0
2018	0	0	0	0	29	3	0
2019	0	0	0	0	31	3	0
2020	0	0	0	0	30	3	0
2021	0	0	0	0	31	3	0
2022	0	0	0	0	30	3	0
2023	0	0	0	0	32	3	0
2024	0	0	0	0	32	3	0
2025	0	0	0	0	22	2	0
2026	0	0	0	0	30	3	0
2027	0	0	0	0	25	3	0
2028	0	0	0	0	28	3	0
2029	0	0	0	0	30	3	0
2030	0	0	0	0	27	3	0
2031	0	0	0	0	28	3	0
2032	0	0	0	0	28	3	0
2033	0	0	0	0	13	1	0
2034	0	0	0	0	38	4	0
2035	0	0	0	0	28	3	0
2036	0	0	0	0	29	3	0
2037	0	0	0	0	22	2	0
2038	0	0	0	0	26	3	0
2039	0	0	0	0	27	3	0
2040	0	0	0	0	19	2	0

	Summary of Energy Purchases and Sales (Gwh): Internal Requirement	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	TOTAL RATE IMPACT CAGR (thru)
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0
2015	(0)	0	0	0	121	(685)	(805)	(0)	0	(7,524)	(0)	(0)
2016	(0)	0	0	0	(46)	42	89	(0)	0	(11,031)	(0)	(0)
2017	0	0	0	0	(50)	32	82	0	0	(8,933)	(0)	(0)
2018	0	0	0	0	(42)	36	78	0	0	(7,390)	(0)	(0)
2019	(0)	0	0	0	(54)	32	86	(0)	0	(8,688)	(0)	(0)
2020	(0)	0	0	0	(41)	39	80	(0)	0	(10,240)	(0)	(0)
2021	0	0	0	0	(40)	43	82	0	0	(11,634)	(0)	(0)
2022	0	0	0	0	(40)	37	77	0	0	(13,046)	(0)	(0)
2023	0	0	0	0	(58)	29	87	0	0	(14,175)	(0)	(0)
2024	0	0	0	0	(56)	31	87	0	0	(15,252)	(0)	(0)
2025	0	0	0	0	0	57	57	0	0	(16,951)	(0)	(0)
2026	0	0	0	0	(13)	66	79	0	0	(17,674)	(0)	(0)
2027	0	0	0	0	(3)	63	66	0	0	(18,377)	(0)	(0)
2028	(0)	0	0	0	(11)	62	74	(0)	0	(18,849)	(0)	(0)
2029	0	0	0	0	(17)	62	80	0	0	(19,113)	(0)	(0)
2030	(0)	0	0	0	(7)	63	70	(0)	0	(19,520)	(0)	(0)
2031	0	0	0	0	(14)	61	75	0	0	(19,908)	(0)	(0)
2032	(0)	0	0	0	(11)	63	74	(0)	0	(20,461)	(0)	(0)
2033	0	0	0	0	17	53	36	0	0	(21,794)	(0)	(0)
2034	0	0	0	0	(19)	83	102	0	0	(21,298)	(0)	(0)
2035	(0)	0	0	0	(13)	61	74	(0)	0	(21,950)	(0)	(0)
2036	0	0	0	0	(12)	63	75	0	0	157,968	2	0
2037	0	0	0	0	(2)	54	56	0	0	157,618	2	0
2038	(0)	0	0	0	(13)	56	68	(0)	0	157,210	2	0
2039	0	0	0	0	(14)	56	70	0	0	156,790	2	0
2040	0	0	0	0	(5)	42	47	0	0	126,437	2	0

	East Reserve Margin - MW: Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	0	0		0	0	0
2012	0	0		0	0	0
2013	0	0		0	0	0
2014	0	0		0	0	0
2015	0	(257)		0	(257)	(0)
2016	0	124	1 -904 MW NGCC,	0	124	0
2017	0	124		0	124	0
2018	0	124		0	124	0
2019	0	124		0	124	0
2020	0	124		0	124	0
2021	0	124		0	124	0
2022	0	124		0	124	0
2023	0	124		0	124	0
2024	0	124		0	124	0
2025	0	124	1- 407 MW CC,	0	124	0
2026	0	124		0	124	0
2027	0	124		0	124	0
2028	0	124		0	124	0
2029	0	124		0	124	0
2030	0	124		0	124	0
2031	0	124		0	124	0
2032	0	124		0	124	0
2033	0	124		0	124	0
2034	0	124		0	124	0
2035	0	124		0	124	0
2036	0	124		0	124	0
2037	0	124		0	124	0
2038	0	124		0	124	0
2039	0	124		0	124	0
2040	0	124		0	124	0

[A] Total East SO2 Excludes Cardinal 2&3 Emissions
[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Resource Planning
Created on: October 6, 2011

~3813059.xlsx
FTCA CSAPR CC - Repower

Forward Power Prices

Help

Tools

Settings

Region PJM

As Of 4/29/2012 Today

Peak Off Peak

Apply Restore Defaults

Chart | Data

As of: 4/27/2012

Term	AEP-DAYTON HUB	BGE	COMED	DPL	EASTERN HUB	JCPL	N ILLINOIS HUB	PEPCO	PPL	PSEG	WESTERN HUB
Apr. 2012	24.50	29.45	20.82	23.67	23.58	23.45	20.59	28.13	23.06	23.80	25.68
May. 2012	23.41	27.56	20.45	28.83	25.89	27.41	19.73	27.34	25.79	27.67	25.04
Jun. 2012	24.47	29.95	21.72	27.67	-	29.02	20.99	29.79	26.67	27.37	26.64
Jul. 2012	26.01	32.24	24.42	30.01	-	30.74	23.69	31.99	29.02	30.94	28.99
Aug. 2012	26.01	32.24	24.42	30.01	-	30.74	23.69	31.99	29.02	30.94	28.99
Sep. 2012	23.99	29.50	20.15	27.22	-	28.57	19.43	29.34	26.22	26.92	26.19
Oct. 2012	26.04	28.03	21.49	26.68	-	28.65	20.76	28.80	26.15	26.85	25.65
Nov. 2012	26.04	29.63	21.49	28.28	-	30.25	20.76	30.40	27.75	28.45	27.25
Dec. 2012	26.04	34.50	21.49	33.15	-	35.13	20.76	35.28	32.63	33.33	32.13
Jan. 2013	29.41	40.15	25.21	37.86	-	38.34	24.48	40.96	36.87	37.56	36.84
Feb. 2013	29.41	40.15	25.21	37.86	-	38.34	24.48	40.96	36.87	37.56	36.84
Mar. 2013	29.41	33.83	25.21	31.54	-	32.02	24.48	34.64	30.55	31.25	30.52
Apr. 2013	29.41	33.83	25.21	31.54	-	32.02	24.48	34.64	30.55	31.25	30.52
May. 2013	29.41	32.11	25.21	29.83	-	30.30	24.48	32.93	28.84	29.53	28.80
Jun. 2013	29.41	35.60	25.21	32.25	-	-	24.48	-	31.30	32.35	30.10
Jul. 2013	29.41	38.05	25.21	34.70	-	-	24.48	-	33.75	34.80	32.55
Aug. 2013	29.41	38.05	25.21	34.70	-	-	24.48	-	33.75	34.80	32.55
Sep. 2013	29.41	34.52	25.21	31.17	-	-	24.48	-	30.22	31.27	29.02
Oct. 2013	29.41	36.67	25.21	33.32	-	-	24.48	-	32.37	33.42	31.17
Nov. 2013	29.41	36.67	25.21	33.32	-	-	24.48	-	32.37	33.42	31.17
Dec. 2013	29.41	36.67	25.21	33.32	-	-	24.48	-	32.37	33.42	31.17
Jan. 2014	31.64	38.75	27.15	40.01	-	-	26.43	-	36.50	38.66	34.16
Feb. 2014	31.64	38.75	27.15	40.01	-	-	26.43	-	36.50	38.66	34.16
Mar. 2014	31.64	38.75	27.15	40.01	-	-	26.43	-	36.50	38.66	34.16
Apr. 2014	31.64	38.75	27.15	40.01	-	-	26.43	-	36.50	38.66	34.16
May. 2014	31.64	38.75	27.15	40.01	-	-	26.43	-	36.50	38.66	34.16
Jun. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Jul. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Aug. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Sep. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Oct. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Nov. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Dec. 2014	31.64	38.75	27.15	-	-	-	26.43	-	36.50	38.66	34.16
Jan. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	40.73	36.23
Feb. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	40.73	36.23
Mar. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	40.73	36.23
Apr. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	40.73	36.23
May. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	40.73	36.23
Jun. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Jul. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Aug. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Sep. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Oct. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Nov. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Dec. 2015	33.68	40.82	28.44	-	-	-	27.62	-	38.57	-	36.23
Jan. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Feb. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Mar. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Apr. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
May. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Jun. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Jul. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Aug. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Sep. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Oct. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Nov. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Dec. 2016	-	42.85	-	-	-	-	-	-	-	-	38.27
Jan. 2017	-	44.74	-	-	-	-	-	-	-	-	40.15
Feb. 2017	-	44.74	-	-	-	-	-	-	-	-	40.15
Mar. 2017	-	44.74	-	-	-	-	-	-	-	-	40.15
Apr. 2017	-	44.74	-	-	-	-	-	-	-	-	40.15
May. 2017	-	44.74	-	-	-	-	-	-	-	-	40.15

KIUC EXHIBIT 12

If there is no data available for the selected date, the most recent data as of the selected date is displayed.

NYMEX and CME Clearport market data provided by DTN.

Alberta and Ontario Canadian power prices are reported in C$/MWh. U.S. power locations are reported in US$/MWh.

Forward Power Prices

Help

Tools

Settings

Region PJM

As Of 4/29/2012 Today

Peak On Peak

Apply | Restore Defaults

Chart | Data

As of: 4/27/2012

Term	AEP-DAYTON HUB	BGE	COMED	DPL	EASTERN HUB	JCPL	N ILLINOIS HUB	PEPCO	PPL	PSEG	WESTERN HUB
Apr. 2012	31.11	39.00	28.73	31.29	31.41	31.02	28.54	37.36	30.82	31.29	35.53
May. 2012	33.05	40.35	31.65	43.34	39.60	39.43	30.65	38.98	37.85	38.60	36.10
Jun. 2012	35.45	45.16	33.42	43.98	-	43.28	32.42	44.10	38.83	41.22	39.95
Jul. 2012	41.54	56.53	40.28	51.68	-	52.65	39.28	54.65	52.03	52.78	47.65
Aug. 2012	41.54	55.58	40.28	50.73	-	51.70	39.28	53.70	51.08	51.83	46.70
Sep. 2012	33.13	42.69	31.15	41.50	-	40.81	30.15	41.63	36.35	38.74	37.48
Oct. 2012	33.68	42.46	31.00	39.36	-	41.33	30.00	39.48	37.83	41.96	35.33
Nov. 2012	33.68	43.46	31.00	40.36	-	42.33	30.00	40.48	38.83	42.96	36.33
Dec. 2012	33.68	47.76	31.00	44.66	-	46.63	30.00	44.78	43.13	47.26	40.63
Jan. 2013	39.19	49.38	36.48	49.52	49.77	43.60	36.48	48.32	43.05	45.44	44.17
Feb. 2013	39.19	49.38	36.48	49.52	49.77	43.60	36.48	48.32	43.05	45.44	44.17
Mar. 2013	36.96	45.61	33.36	45.75	46.00	39.83	33.36	44.55	39.28	41.67	40.40
Apr. 2013	36.96	45.61	33.36	45.75	46.00	39.83	33.36	44.55	39.28	41.67	40.40
May. 2013	37.30	45.67	34.20	45.81	46.06	39.89	34.20	44.61	39.34	41.73	40.46
Jun. 2013	41.53	50.94	38.13	50.79	48.72	48.69	38.13	49.56	46.84	48.69	45.44
Jul. 2013	48.11	58.97	45.39	58.82	56.76	56.72	45.39	57.60	54.87	56.72	53.47
Aug. 2013	48.11	58.97	45.39	58.82	56.76	56.72	45.39	57.60	54.87	56.72	53.47
Sep. 2013	38.68	48.56	34.98	48.41	46.34	46.31	34.98	47.18	44.46	46.31	43.06
Oct. 2013	37.35	46.59	33.14	46.44	44.37	44.34	33.14	45.21	42.49	44.34	41.09
Nov. 2013	37.35	46.59	33.14	46.44	44.37	44.34	33.14	45.21	42.49	44.34	41.09
Dec. 2013	37.35	46.59	33.14	46.44	44.37	44.34	33.14	45.21	42.49	44.34	41.09
Jan. 2014	42.73	52.15	39.06	52.62	-	51.57	39.06	50.90	49.11	51.27	46.77
Feb. 2014	42.73	52.15	39.06	52.62	-	51.57	39.06	50.90	49.11	51.27	46.77
Mar. 2014	42.73	52.15	39.06	52.62	-	51.57	39.06	50.90	49.11	51.27	46.77
Apr. 2014	42.73	52.15	39.06	52.62	-	51.57	39.06	50.90	49.11	51.27	46.77
May. 2014	42.73	52.15	39.06	52.62	-	51.57	39.06	50.90	49.11	51.27	46.77
Jun. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Jul. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Aug. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Sep. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Oct. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Nov. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Dec. 2014	42.73	52.15	39.06	-	-	51.57	39.06	-	49.11	51.27	46.77
Jan. 2015	44.90	54.21	41.18	-	-	53.63	40.73	-	51.17	53.33	48.83
Feb. 2015	44.90	54.21	41.18	-	-	53.63	40.73	-	51.17	53.33	48.83
Mar. 2015	44.90	54.21	41.18	-	-	53.63	40.73	-	51.17	53.33	48.83
Apr. 2015	44.90	54.21	41.18	-	-	53.63	40.73	-	51.17	53.33	48.83
May. 2015	44.90	54.21	41.18	-	-	53.63	40.73	-	51.17	53.33	48.83
Jun. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Jul. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Aug. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Sep. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Oct. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Nov. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Dec. 2015	44.90	54.21	41.18	-	-	-	40.73	-	51.17	-	48.83
Jan. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Feb. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Mar. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Apr. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
May. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Jun. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Jul. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Aug. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Sep. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Oct. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Nov. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Dec. 2016	-	56.13	-	-	-	-	-	-	-	-	50.75
Jan. 2017	-	58.28	-	-	-	-	-	-	-	-	52.90
Feb. 2017	-	58.28	-	-	-	-	-	-	-	-	52.90
Mar. 2017	-	58.28	-	-	-	-	-	-	-	-	52.90
Apr. 2017	-	58.28	-	-	-	-	-	-	-	-	52.90
May. 2017	-	58.28	-	-	-	-	-	-	-	-	52.90

KIUC EXHIBIT 13

If there is no data available for the selected date, the most recent data as of the selected date is displayed.

NYMEX and CME Clearport market data provided by DTN.

Alberta and Ontario Canadian power prices are reported in C$/MWh. U.S. power locations are reported in US$/MWh.

For your protection, your IP address has been logged:
66.117.241.194

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: **APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANTING OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES**	CASE NO. 2011-00401

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MAR 09 2012

PUBLIC SERVICE COMMISSION

<u>Notice of Filing Of Supplemental Response</u>
<u>To Identified Data Requests</u>

Kentucky Power Company files its March 9, 2012 Supplemental Response to the following data requests:

(a) KIUC 1-41;

(b) AG 1-26.

OAG EXHIBIT 1

Respectfully submitted,

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COUNSEL FOR KENTUCKY POWER COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail upon the following parties of record, this the 9th day of March, 2012.

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MOODY'S
INVESTORS SERVICE

Credit Opinion: Kentucky Power Company

Global Credit Research - 07 Feb 2012

Ashland, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Parent: American Electric Power Company, Inc.	
Outlook	Stable
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2

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Key Indicators

[1]Kentucky Power Company

	LTM 9/30/2011	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	3.9x	3.4x	3.9x	2.5x
(CFO Pre-W/C) / Debt	18%	15%	18%	9%
(CFO Pre-W/C - Dividends) / Debt	14%	11%	15%	7%
Debt / Book Capitalization	44%	46%	46%	50%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Constructive regulatory environment viewed positively

Planned environmental expenditures enormous relative to the company's size

Key financial metrics have improved but likely to be stressed by the capital spending program

Maintenance of current ratings will depend on capital injections from the parent

Industrial sales have benefitted from high component of mining and energy-related industries

Corporate Profile

Kentucky Power Company (KPCo, Baa2 senior unsecured, stable outlook) is a vertically integrated electric utility company headquartered in Frankfort, Kentucky and is a wholly owned subsidiary of American Electric Power Company (AEP, Baa2 senior unsecured, stable outlook). KPCo is one of AEP's smaller subsidiaries, with about $1 billion in rate base (about 6% of AEP's state jurisdictional total) and $1.6 billion assets (3% of AEP consolidated). KPCo's primary regulator is the Kentucky Public Service Commission (KPSC). KPCo's total owned generation capacity is 1,078 MW, entirely at the Big Sandy plant, and it purchases approximately 390 MW from affiliate AEP Generating's share of the Rockport plant under two long-term unit power agreements. KPCos total capacity of approximately 1,468 MW is 100% coal. KPCo's 2010 peak demand was reported as 1,543 MW, leaving a negative reserve margin of approximately 5%, which KPCO has primarily met with purchases from its affiliates in the AEP Power Pool.

SUMMARY RATING RATIONALE

KPCo's Baa2 senior unsecured rating primarily reflects the reasonably constructive relationship with the KPSC, financial metrics that have improved to a level that is consistent with the rating, and the company's position as a member of the AEP family, balanced against an enormous planned capital expenditure program that could stress financial metrics, a need for capital injections during the construction period and the impact of an expected near doubling of rate base on retail rates.

DETAILED RATING CONSIDERATIONS

CONSTRUCTIVE REGULATORY ENVIRONMENT A CREDIT POSITIVE

Moody's views the regulatory environment in Kentucky as reasonably supportive to long-term credit stability, a material credit positive. In June, 2010, the KPSC approved a not overly-generous rate settlement agreement for KPCo authorizing a $64 million rate increase, based on a 10.5% authorized ROE with 43% equity, and recovery of $23 million of storm costs over five years. However, electric utilities have generally been allowed to earn a return on essentially all construction work in progress. Utilities can start to collect interim rates approximately six months after filing a rate case if the KPSC has not acted on it. There are also various riders and cost recovery mechanisms that help to avoid regulatory lag, including a fuel adjustment clause, an energy efficiency rider and, most significantly, an environmental cost recovery rider. Proceedings for the latter are conducted every two years. The KPSC has authorized significant amounts of environmental spending for some of the state's other investor-owned utilities, and Moody's expects that KPCo would be granted similar treatment for reasonable costs to upgrade its coal plants.

CAPITAL EXPENDITURE PROGRAM COULD PRESSURE RATINGS OVER THE MEDIUM TO LONG TERM

KPCo's cumulative long-term capital investment program is extremely large relative to its size. KPCo terminated its installation of jet bubbling reactor technology at Big Sandy 2 due to technical problems and expects to install dry flue gas desulfurization at unit two (800 MW), while retiring unit one (278 MW). On 12/5/11, KPCo filed with the KPSC to approve the project at an estimated cost of $940 million including AFUDC. KPCo proposes to defer a return on the project until it is complete (estimated in 2016) implying environmental capex of about $270 million/year, compared to average annual total capex of $80 million for 2006-2010. KPCo will also be responsible for a portion of the cost of the Rockport upgrades, but KPCo will pay these costs over a longer period of time through higher capacity costs. To maintain its current rating, KPCo will require additional equity injections from AEP (the last received was in 2009), especially if cash returns are deferred as proposed. Based in part on our expectation that coal-friendly investments will receive timely rate base treatment in Kentucky, we expect that the parent will take appropriate steps to maintain adequate financial metrics at KPCo.

Another potential concern regarding environmental expenditures is the impact on rates. KPCo's average residential rate of 8.85 cents/KWh in 2010 was the highest among investor-owned utilities in the state, and 16% higher than the state average of 7.63 cents/KWh. KPCo estimates that the Big Sandy expenditures will raise rates by about 30% in 2016; however, rates for all utilities in the state will increase due to similarly large expenditures. Higher rates could engender demand response changes among all customer classes. Rate design will be an important consideration, as materially higher rates could discourage industrial activity and/or encourage self generation by large industrial customers, especially if shale gas keeps natural gas prices depressed.

RECENTLY STABLIZED CREDIT METRICS MAY BE STRESSED BY THE ENVIRONMENTAL SPENDING

KPCo's key financial credit metrics have historically been somewhat weak for its Baa2 senior unsecured rating category but have improved since 2008. For the periods of 2006-2010, 2008-2010 and the twelve months ended 9/30/11, KPCo's ratio of cash from operations before working capital adjustments (CFO pre-W/C) to debt averaged about 14.5%, 13.7% and 18.3%, respectively. The ratio of CFO pre-w/c interest coverage averaged 3.6x, 3.3x and 3.7x, respectively for the same periods. Balance sheet leverage has also improved, with debt to capitalization of 44.2% at 9/30/11, down from 50.5% at 12/31/08. In the near to intermediate term, we expect financial metrics to stabilize. However, metrics will likely be stressed after mid-2013, due to large increases in capital expenditures, potentially with no current return on investment if the KPSC agrees to the proposed deferral. Thus, our expectation that AEP will provide sufficient equity capital to maintain metrics is crucial to the continuance of the current ratings.

INDUSTRIAL SALES HAVE HELD STEADY, BOOSTED BY COAL MINING AND ENERGY

Although KPCo's service territory is in the easternmost part of the state, with few urban areas other than Ashland, industrial sales represent a high percentage of total production, - about 44% of retail KWh sales and 34% of retail revenues. Of the 10 largest industrial customers, which represent 66% of industrial sales, there are four coal mining companies, two energy companies, two steel manufacturers, and two chemical companies. Industrial sales have been quite stable over the past five years, in part because high coal prices have kept the mines active. Recent Central Appalachian coal price declines could negatively affect overall KWh demand; however, KPCo's territory is on the western edge of the Utica shale formation, which may spur further energy development.

DISSOLUTION OF THE AEP POWER POOL ADDS A MODICUM OF UNCERTAINTY

In December 2010, all the members of the AEP Power Pool gave notice to terminate the Interconnection Agreement under which they purchase and sell power and share the costs of capacity, effective January 2014 or as determined by FERC. While this notice is revocable, we believe the Interconnection Agreement will be cancelled or materially modified. KPCo is weakly positioned to serve its own load; however, the expected de-regulation of AEP Ohio's generation in stages through mid-2015 provides a potential source of long-term power and capacity for KPCo.

Liquidity

KPCO's liquidity is adequate. KPCO participates in the AEP Utility Money Pool with a borrowing limit of $250 million, which provides access to the parent company's liquidity. As of 9/30/11, KPCO had a balance of $96 million invested in the Money Pool, compared to the $67 million invested as of 12/31/10. KPCo also utilizes AEP's receivable securitization facility.

For the twelve months ending September 2011, KPCO generated approximately $140 million of cash from operations, invested approximately $64 million in capital expenditures and made $24 million in upstream dividend payments to AEP, resulting in approximately $52 million of positive free cash flow. In 2012, we expect KPCO to generate approximately $120 million of cash from operations, invest approximately $120 million in capital expenditures and continue to contribute approximately $20 million in upstream dividends to its parent. KPCO has no long-term debt maturities until 2017.

AEP has two syndicated credit facilities totaling $3.25 billion that were renewed and extended in mid-2011. One is a $1.5 billion facility expiring June 2015. The other is a $1.75 billion facility (upsized from $1.5 billion) expiring in July 2016. The combined letter of credit sub-limits under these facilities is $1.35 billion. The facilities contain a covenant requiring that AEP's consolidated debt to capitalization (as defined) will not exceed 67.5% (AEP states the actual ratio was 50.3% at 9/30/11, indicating substantial headroom). AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under the facility. Default provisions exclude payment defaults and insolvency/bankruptcy of subsidiaries that (like KPCo) are not significant subsidiaries per the SEC definition (AEP Texas Central and Southwestern Electric Power Company are also effectively excluded as significant subsidiaries due to definitional adjustments). Also in 2011, AEP allowed a $478 million letter of credit facility to expire but renewed its $750 million accounts receivable securitization (only the multi-year portion of the latter is included as an available source in Moody's liquidity testing).

As of 9/30/11, AEP had $546 million of cash on hand and approximately $2.6 billion of availability under the syndicated revolving credit facilities after giving effect to $529 million of commercial paper outstanding and $103 million of issued letters of credit.

For the 12 months ended 9/30/11, AEP generated approximately $4.6 billion in cash from operations, made approximately $3.1 billion in capital investments and net asset purchases and paid about $890 million in dividends, resulting in roughly $610 million of positive free cash flow.

Including securitization bonds, AEP has approximately $690 million of long-term debt due in 2012, $1.7 billion due in 2013, and $1.0 billion in 2014. Over the next two years, we estimate that AEP will generate roughly $3.5 billion in cash from operations, spend about $3.3 billion annually in capital expenditures and pay approximately $900-950 million in dividends annually, yielding negative free cash flow of about $700 million per year.

Rating Outlook

The stable rating outlook for KPCo is primarily based on our expectation that the company will continue to maintain a constructive relationship with the KPSC, including reasonably good recovery of planned environmental upgrade expenditures, and that parent AEP will provide the capital injections needed for KPCo to maintain the recently stabilized key financial credit metrics that support the current rating.

What Could Change the Rating - Up

Rating upgrades appear unlikely over the near to intermediate term horizon, primarily due to our expectation that KPCo will be challenged to maintain its financial profile in light of the capital investment plan. However, KPCo could be considered for a ratings upgrade if it were to achieve key financial credit metrics, including CFO pre W/C plus interest over interest of approximately 5x and CFO pre W/C to debt of approximately 20% on a sustainable basis.

What Could Change the Rating - Down

Ratings could be downgraded if the regulatory environment were to take a more adversarial tone, especially with respect to the recent environmental capex filing, if KPCo's capital expenditure program experienced material cost over-runs, if equity contributions from AEP were not forthcoming in a manner to maintain financial metrics commensurate with the current rating, if there were a material, sustained decrease in retail sales and revenues (especially from industrial customers), or the key financial credit metrics exhibited a deterioration that we expected would be prolonged, for instance, a ratio of CFO pre W/C plus interest over interest below 3.0x or CFO pre W/C to debt in the low-teens.

Rating Factors

Kentucky Power Company

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2010**		**Moody's 12-18 month Forward View* As of February 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		B		B
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	3.2x	Baa	3.0 - 3.5x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	13.7%	Baa	13 - 17%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	10.8%	Baa	13 - 17%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	47.3%	Baa	45 - 55%	Ba
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW;
NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED
IN THE TEXT DOES NOT INCORPORATE
SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

Moody's
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANTING OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES

CASE NO. 2011-00401

RECEIVED

FEB 22 2012

PUBLIC SERVICE COMMISSION

Notice of Filing Of Supplemental Response To Identified Data Request

Following discussions with counsel clarifying the information being sought in AG 1-11(c), Kentucky Power Company files the following supplemental response to AG 1-11.

This the 22nd day of February, 2012.

Respectfully submitted,

Mark R. Overstreet
R. Benjamin Crittenden
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Frankfort, KY 40602-0634
Telephone: (502) 223-3477
COUNSEL FOR KENTUCKY POWER COMPANY

OAG EXHIBIT 2

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by hand delivery or overnight delivery upon the following parties of record, this the 22nd day of February, 2012.

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
Suite 1510
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Joe F. Childers
Joe F. Childers & Associates
300 The Lexington Building
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Dennis G. Howard II
Lawrence W. Cook
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Frankfort, KY 40602-2000

Kristin Henry
Sierra Club
85 Second Street
San Francisco, CA 94105

Mark R. Overstreet

Kentucky Power Company

REQUEST

Please reference the Weaver testimony at pages 12 through 13 as well as the testimony in general. Please provide a chart or graphical depiction of the following, broken down by Phase 1 and Phase 2 of the CSAPR Rule:

a. The estimated curtailment date(s), if any, of the Big Sandy units, with each unit listed separately, and amount of generated electricity expected to be curtailed;

b. The amounts and expected costs of any additional power that may have to be purchased as a result of any such curtailments;

c. The estimated impact on the bills of average residential, commercial and industrial customers, with each listed separately, including also the costs of any purchased power reflected in subpart (b), above.

RESPONSE

a. Please see the response to KPSC 1-8.

b. Please see the response to KSPC 1-52 (e).

c. Please see page 2 of 2 of this Response for the requested chart. The average customer bill for each customer class was calculated by dividing total revenue for each customer class during 2011 by the simple average number of class customers during 2011. The calculated average bill was then increased by the indicated percentage in 2012, 2013, and 2016.

Because the environmental surcharge is calculated as a percentage of revenue, the increase, expressed as a percentage, will be the same in 2012, 2013, and 2016 (0.87%, 0.01%, and 28.62% respectively) without regard to the amount of the bill.

WITNESS: Robert L Walton and Lila P Munsey

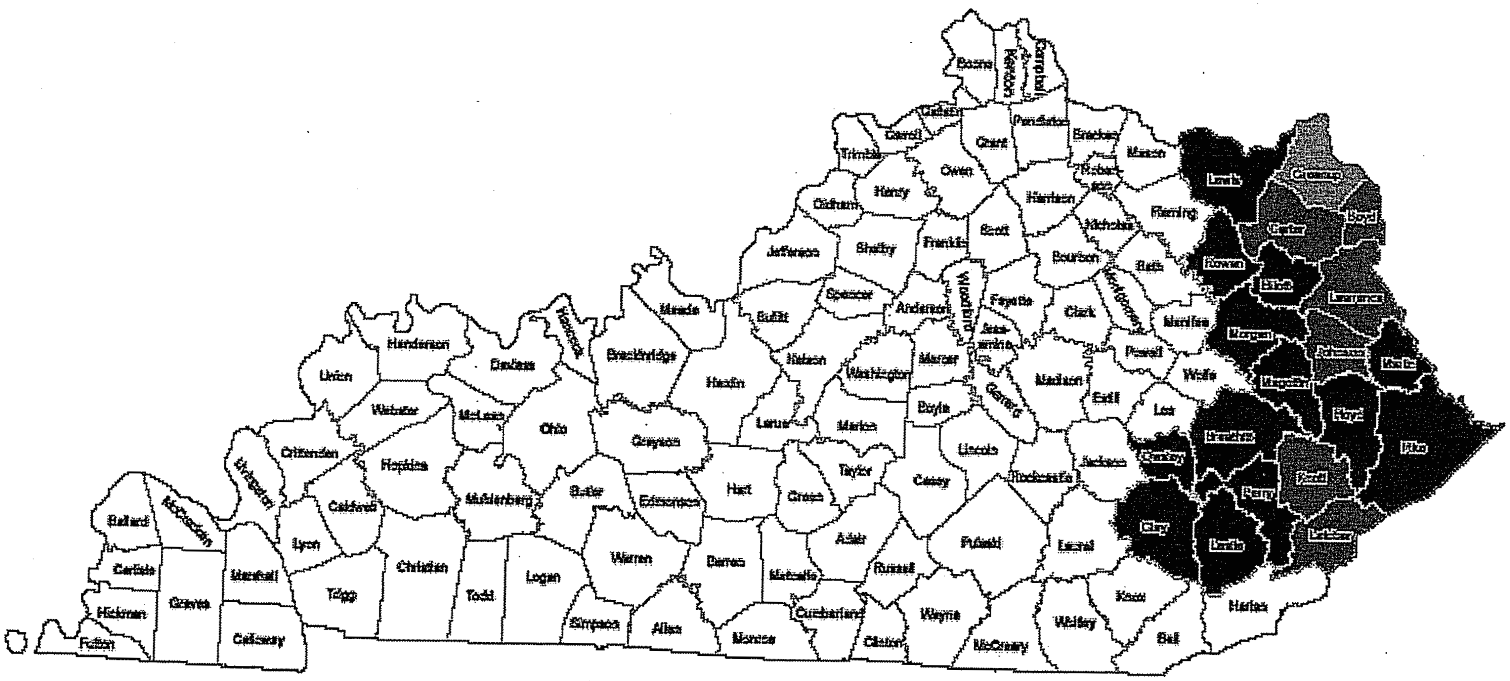
Kentucky Power Company
KPSC Case No. 2011-00401
Estimated Average Residential, Commercial, and Industrial Customer Bills

Estimated Average Bills and Increases	2011	2012	2013	2014	2015	2016
ECR Percent Increase		0.87%	0.01%	0.00%	0.00%	28.61%
Residential Bill	$ 132.86	$ 134.02	$ 134.03	$ 134.03	$ 134.03	$ 172.05
Residential Bill Increase		$ 1.16	$ 0.01	$ -	$ -	$ 38.02
Commercial Bill	$ 376.89	$ 380.17	$ 380.21	$ 380.21	$ 380.21	$ 488.07
Commercial Bill Increase		$ 3.28	$ 0.04	$ -	$ -	$ 107.86
Industrial Bill	$11,608.80	$11,709.79	$11,710.95	$11,710.95	$11,710.95	$15,033.39
Industrial Bill Increase		$ 100.99	$ 1.16	$ -	$ -	$ 3,322.44

Kentucky: 18.9 Percent

4.1 - 12.2
12.3 - 15.4
15.5 - 18.6
18.7 - 26.4
26.5 - 45.4

Counties in AEP Service Area
Percent of Persons in Poverty 2010



http://ksdc.louisville.edu/1income.htm

http://ksdc.louisville.edu/sdc/poverty/SAIPE2010_ky.xls 2010 Poverty Rates for Kentucky and Counties

OAG EXHIBIT 3

300 American Electric Power

Electric Operation and Maintenance Expenses - 1. Power Production (Ref Pg. 320)

	Amount for Current Yr	Amount for Previous Yr
POWER PRODUCTION EXPENSES		
A. Steam Power Generation		
Operation		
Operation Supervision and Engineering (500)	$4,789,470.00	$4,946,854.00
Fuel (501)	$174,003,691.00	$182,833,323.00
Steam Expenses (502)	$4,958,775.00	$4,744,990.00
Steam from Other Sources (503)		
(Less) Steam Transferred CR (504)		
Electric Expenses (505)	$36,817.00	$96,981.00
Miscellaneous steam Power Expenses (506)	$9,471,055.00	$3,204,129.00
Rents (507)		
Allowance (509)	$7,852,010.00	$2,326,582.00
Total Operation	**$201,111,818.00**	**$198,152,859.00**
Maintenance		
Maintenance Supervision and Engineering (510)	$436,657.00	$455,751.00
Maintenance of Structures (511)	$720,207.00	$911,931.00
Maintenance of Boiler Plant (512)	$10,421,344.00	$8,057,559.00
Maintenance of Electric Plant (513)	$5,098,686.00	$1,890,814.00
Maintenance of Miscellaneous Steam Plant (514)	$691,642.00	$617,265.00
Total Maintenance	**$17,368,536.00**	**$11,933,320.00**
21. Total Power Production Expenses -- Steam Power	**$218,480,354.00**	**$210,086,179.00**
B. Nuclear Power Generation		
Operations		
Operation Supervision and Engineering (517)		
Fuel (518)		
Coolants and water (519)		
Steam Expenses (520)		
Steam from Other Sources (521)		
(Less) Steam Transferred -- CR (522)		

PSC EXHIBIT 1

300 American Electric Power

Steam-Electric Generating Plant Statistics - Part Three (Lines 35-43) (Ref Pg. 402)

	Coal -Tons	Oil - Barrel	Gas - MCF	Nuclear - Indicate	Nuclear Unit
Column b					
Nuclear Unit					
Quantity of Fuel Burned	2,573,985.0000	17,839.00000000	0.0000	0.0000	
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11,941.0000	137,073.00000000	0.0000	0.0000	
Avg Cost of Fuel/unit as Delvd f.o.b. during year	67.5760	98.53300000	0.0000	0.0000	
Average Cost of Fuel per Unit Burned	67.3280	91.05500000	0.0000	0.0000	
Average Cost of Fuel Burned per Million BTU	2.8190	15.81600000	0.0000	0.0000	
Average Cost of Fuel Burned per KWh Net Gen	0.0260	0.00000000	0.0000	0.0000	
Average BTU per KWh Net Generation	9,398.0000	0.00000000	0.0000	0.0000	
Column c					
Nuclear Unit					
Quantity of Fuel Burned					
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)					
Avg Cost of Fuel/unit as Delvd f.o.b. during year					
Average Cost of Fuel per Unit Burned					
Average Cost of Fuel Burned per Million BTU					
Average Cost of Fuel Burned per KWh Net Gen					
Average BTU per KWh Net Generation					
Column d					

EXHIBIT ______

Kentucky Power Company

REQUEST

Provide a revised version of the least-cost analysis used in all of Kentucky Power's original testimony and data responses to date to reflect current conditions within the industry. Provide supporting details and sources for all assumptions, data, and regulatory requirements that drive specific alternatives. Include support for capital costs. Indicate timing issues that may arise with certain alternatives, including environmental requirements. Consider and account for any recent regulatory changes in Ohio or other states that may change the supply chain or availability of materials, equipment, or services. Include at a minimum:

a. PJM energy and capacity costs going forward;

b. Gas prices going forward;

c. Coal prices going forward;

d. Current energy and peak demand projections;

e. Current capital costs for all projects under consideration;

f. Include all previous alternatives, if still available, as well as any new alternatives that may now be available;

g. Consider any recent regulatory changes in Ohio or other states that may change the supply mix or availability;

h. Consider a range of costs for CO_2;

i. Consider a five-year purchased power approach, as well as any longer periods that may be optimum.

RESPONSE

SC EXHIBIT 1

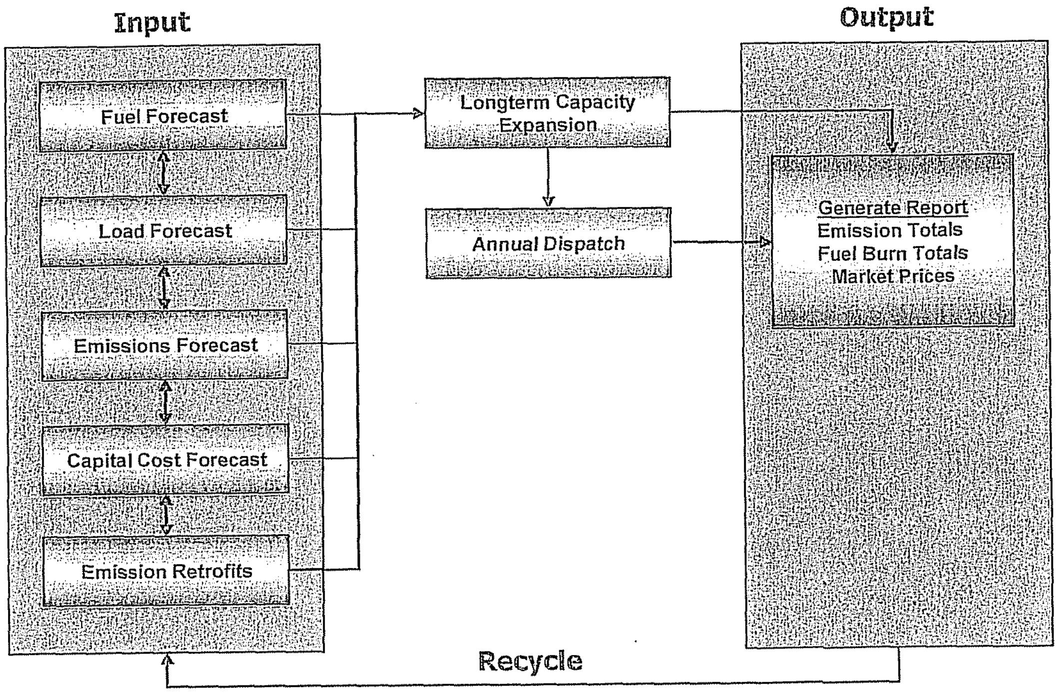
The Company has not revised any of the least cost analyses provided in its testimony or subsequent data responses. The data used in those analyses remains the most current data available. The Long-Term Forecast begins with a fundamental view of the primary input drivers (fuel supply, load, impending regulatory policy, capital costs, etc.) which is developed by internal subject-matter experts and benchmarked to public and contract consultants' information. A third-party dispatch model, Aurora^{XMP}, takes the long-term view of these primary drivers and, after multiple iterations requiring correlative input changes, delivers PJM energy and capacity values, peak demand projections and other power market parameters. The process of creating the Long-Term Forecast takes approximately two months to complete. In addition, it would take another 4 weeks of Strategist work to complete all of the modeling. To this point, there have been no meaningful changes to the primary drivers and accordingly there would be no material differences if the analyses were run to reflect the April 1, 2012 condition in the industry.

In particular:

Natural Gas; The extraordinarily mild 2011-2012 heating season has caused nearby natural gas spot prices to drop to sub-$2/mmBtu levels due to high storage inventories and certain summer storage re-fill congestion. It is equally likely that, in the event of a colder-than-normal heating season, natural gas spot prices could exceed $7/mmBtu. But, on a weather-normalized basis, the fundamentals of natural gas production costs to meet the anticipated total natural gas demand still results in prices equivalent to those projected in Kentucky Power's original testimony for 2013 and beyond. The dominant factor for this observation is that the long-term projection for exploration, development and production costs for shale gas remains unchanged – thus creating a "floor" price. While natural gas prices may incur additional environmental costs due to the process of hydro-fracturing, additional "associated gas" may be brought to market because of the economic advantage of oil/liquids-rich shale plays. But, at this time, there is no reasonable justification to alter the long-term outlook for natural gas prices to Kentucky Power.

Coal; Kentucky Power Company's coal forecast was based upon the long-term costs of coal production and the demand associated with normal weather. It includes assessments of coal-fired plant retirements due to impending environmental regulations and projections of US coal exports due to rising global demand - and these conditions remain unchanged. For the near term, the forecast coal prices will be affected by many other factors, including weather, competing fuel and utility coal stockpile levels. The mild 2011-2012 heating season along with inexpensive natural gas have made coal-fired plant dispatch lower than expected and has left utilities with high stockpiles. This over-supply of coal in the near-term depresses coal prices to such low levels that they are below the cost of production for many less-efficient mines. Coal producers have started to cut down their production to re-balance the supply-demand relationship, and coal prices will recover to cost-of-production based levels in the near-term. Therefore, the forecast prices for the long-term remain valid.

Capacity, energy and peak-demand; The third-party dispatch model, Aurora^{XMP}, has power market values/prices as "outputs" (as shown in the illustration below). Given that there has been no substantive change to the long-term view of the primary input drivers, the outputs and, therefore, the Long-Term Forecast, should remain unchanged.



A range of costs for CO_2; Without question, the creation of a Long-Term Forecast which considers a range of CO_2 costs must include correlative changes to other input drivers. It is imprudent to ignore: 1) the effect of coal plant dispatch costs on coal prices due to changes in demand, 2) changes in gas-fired plant utilization and the effect on natural gas prices, 3) changes in plant retirement schedules, 4) the price elasticity of residential, commercial and industrial demand, for example. The necessary "feedback" loops" (iterations) to create a prudent set of Long-Term Forecasts with a range of costs for CO_2 will require two months to complete.

The Company has not updated any of the capital costs for any of the alternatives and those alternatives provided in the original testimony are still the only alternatives the Company believes are available.

AEP made a filing at FERC in early February 2012 that included a new Power Cost Sharing Agreement (PCSA) that would replace the current pool agreement. As part of the proposed PCSA, KPCo would have purchased a 20% ownership in Mitchell Units 1 and 2. That filing has since been withdrawn, but the Company anticipates resubmitting another filing at a later time this year that will include the purchase of 20% of the Mitchell Units. The transfer of Ohio Power (OPCo) generation to sister companies within AEP was proposed specifically for purposes of supporting the new PCSA. KPCo has no other rights to any additional OPCo generation nor does OPCo have any obligation to KPCo with any additional generation. The Company lacks a reasonable basis to project the availability or price of any additional Ohio generation.

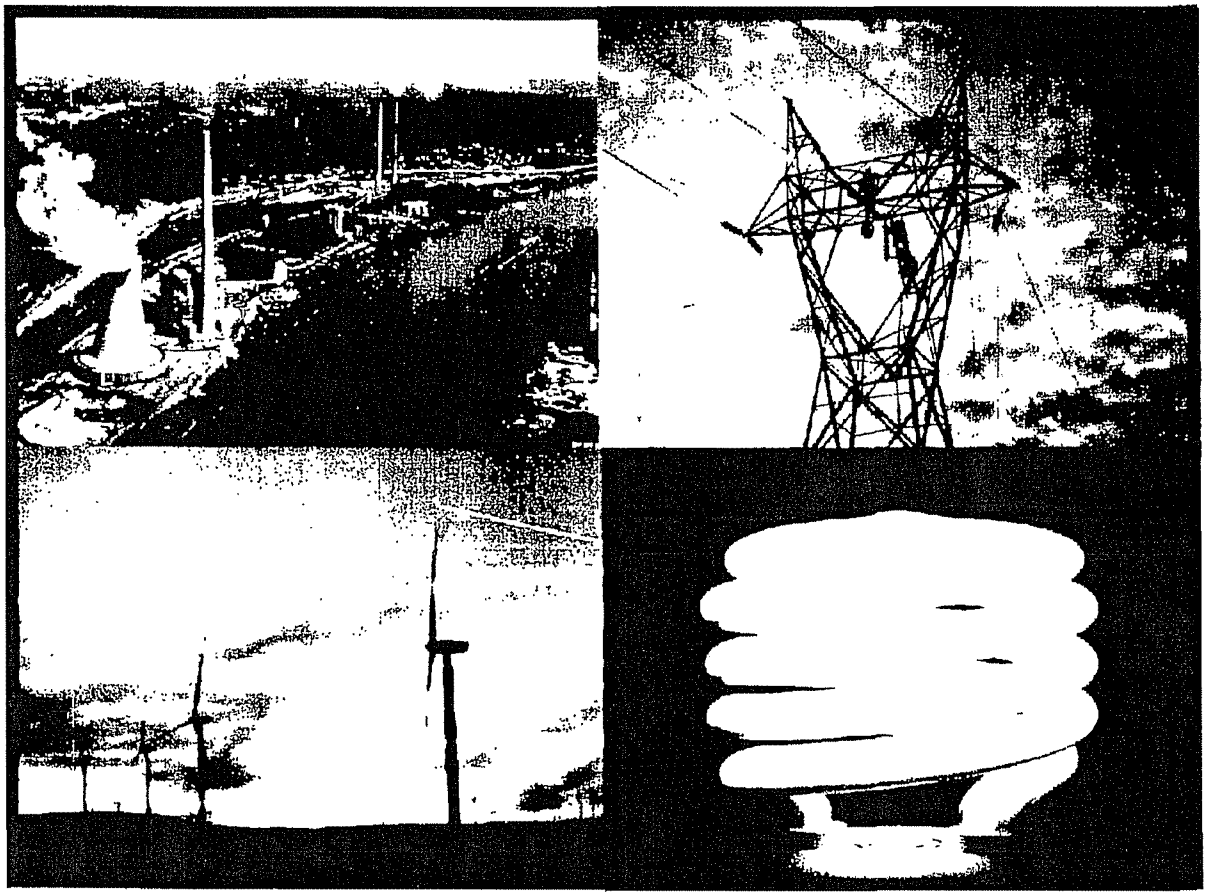
The Company in its application prepared alternative #4A and #4B that looked at both a 5 and 10 year purchase power approach and then would either build or replace with CC capacity. The Company is not able to consider other alternative options at the end of the purchased power approach in the time required to respond to this data request. At a minimum, it would take 8 to 10 weeks to perform the necessary due diligence to evaluate the change in costs due to delaying the DFGD project and economic evaluation of such changes through our modeling exercises.

WITNESS: Scott C Weaver

EXHIBIT ____

AMERICAN ELECTRIC POWER

2010 AEP-EAST INTEGRATED RESOURCE PLAN



2011-2020

Issued: 2010

SC EXHIBIT 2

AMERICAN ELECTRIC POWER

The Integrated Resource Plan (IRP) is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore **this plan is not a commitment to a specific course of action**, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative and regulatory proposals to control carbon, hazardous air pollutants and coal combustion residuals

The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant. It is AEP's intention to revisit and refresh the IRP annually.

The contents of this report contain the Company's forward-looking projections and recommendations concerning the capacity resource profile of its affiliated operating companies located in the PJM Regional Transmission Organization. This report contains information that may be viewed by the public. Business sensitive information has been excluded from this document, but will be made available in a confidential supplement on an as needed basis to third parties subject to execution of a confidentiality agreement. The confidential supplement should be considered strictly **business sensitive and proprietary** and should not be duplicated or transmitted in any manner. Any questions or requests for additional copies of this document should be directed to:

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Acknowledgements

The Resource Planning group appreciates the support and input of the various individuals throughout the Service Corporation who provided input into the development of this Integrated Resource Plan document. In addition, a number of people provided valuable comments as the report was being developed including the operating company regulatory support staffs.

Executive Summary

The goal of resource planning for a largely regulated utility such as AEP is to cost-effectively match its energy supply needs with projected customer demand. As such the plan lays out the ***amount, timing*** and ***type*** of resources that achieve this goal at the lowest reasonable cost, considering all the various constraints—reserve margins, emission limitations, renewable and energy efficiency requirements—that are currently mandated or projected to be mandated.

Planning for future resource requirements during volatile periods can be challenging. The robustness and timing of economic recovery and its impact on load, commodity prices, varying levels of proposed or emerging environmental legislation or federal regulation regarding greenhouse gases/carbon dioxide (GHG/CO_2), hazardous air pollutants (HAPs), coal combustion residuals (CCR) as well as existing and proposed mandates for renewable energy and demand-side management (DSM) represent major "drivers" of uncertainty that must be addressed during this planning process.

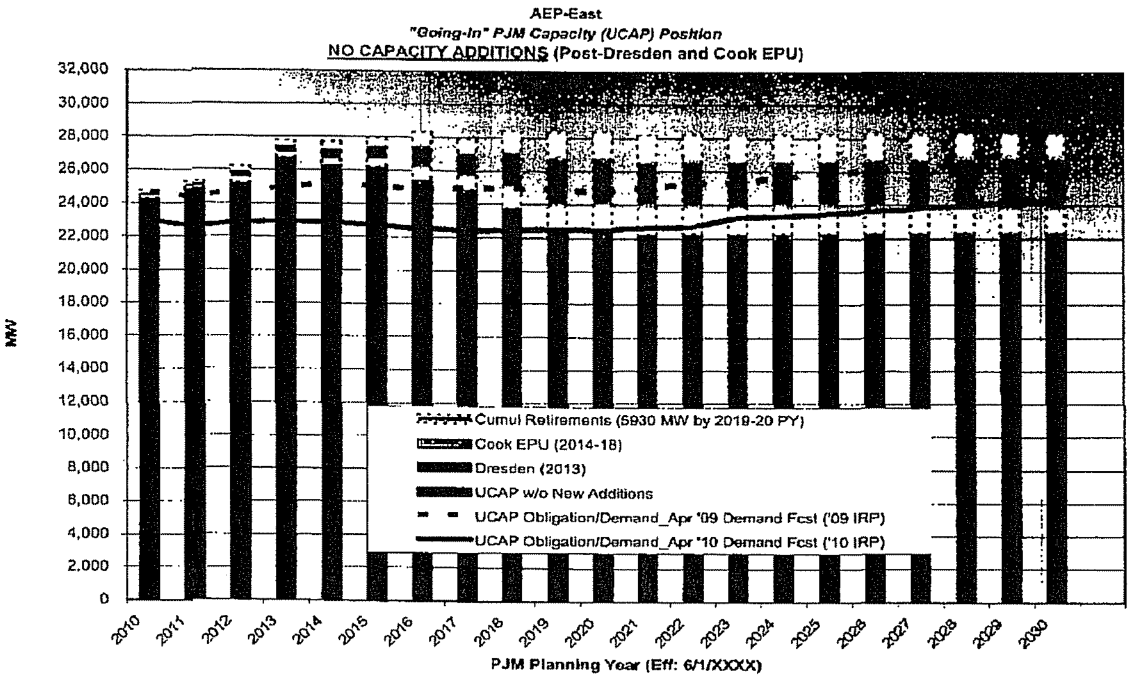
This Executive Summary provides high-level results of the Integrated Resource Plan (IRP or "Plan") process and analyses for the AEP-East zone of the AEP system covering the 10-year period 2011-2020 (Planning Period), with additional modeling and analyses conducted through 2030 (Study Period).[1]

The following **Summary Exhibit 1** offers the "going-in" capacity need of each of the AEP-East zone prior to uncommitted capacity additions. It amplifies that the region's overall capacity need does not occur until the end of the Planning Period (2018-2019). "Committed" new capacity embedded in this Plan includes completion of the 540 MW Dresden combined cycle facility in 2013, the assumed performance of the Donald C. Cook Nuclear Plant Extended Power Uprate (EPU) project, and assumed near-term execution of purchase power agreements for renewable energy (largely, wind) resources.

This going-in capacity profile also considered the potential retirement of close to *6,000 MW* of primarily older, less-efficient coal-fired units over the Planning Period due largely to external factors including known or anticipated environmental initiatives from the U.S. Environmental Protection Agency (EPA), as well as the December 2007 stipulated New Source Review (NSR) Consent Decree. In spite of this potential, this AEP-East IRP requires no new <u>baseload</u> capacity resources in the forecast period. Rather, the proposed EPU initiative at the Cook Nuclear Station during the 2014-2018 time period and peaking resources required in 2017 and 2018, in addition to wind purchases and DSM are assumed to be added to maintain anticipated minimum PJM capacity reserve margin requirements (approximately 15.5% of peak demand) as well as system reliability/restoration needs. It is anticipated that additional natural gas-fired peaking and intermediate capacity would be added shortly after the 2020 Planning Period to meet future load obligations.

[1] Whereas this document focuses on collective affiliate Operating Company planning requirements of the "AEP-West" zone companies operating within the Southwestern Power Pool (SPP) Regional Transmission Organization (RTO), or *"AEP-SPP"*, comparable planning has also been performed for the affiliate *East* zone AEP Operating Companies residing in the PJM RTO.

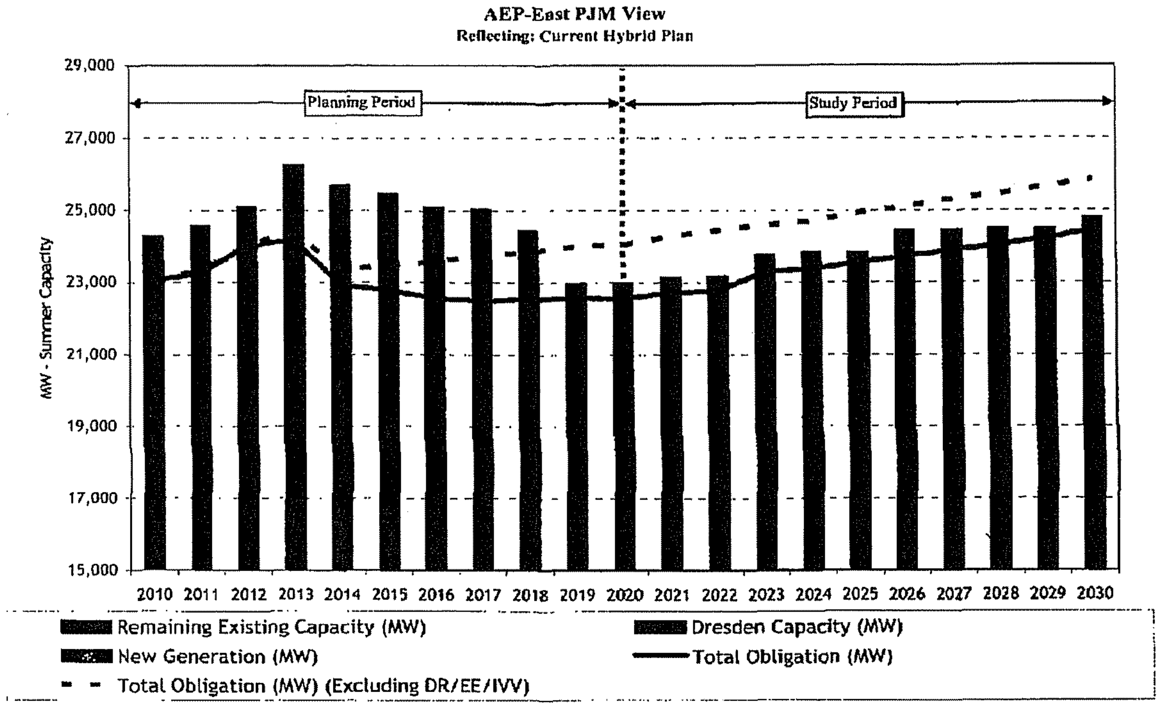
Summary Exhibit 1



Source: AEP Resource Planning

The following **Summary Exhibit 2** demonstrates AEP-East's capacity position relative to this PJM reserve requirement, now inclusive of capacity additions as proposed in this 2010 IRP. As this table indicates, the combination of traditional supply-side additions and demand-side measures that provide demand reductions/energy efficiency (DR/EE) allow AEP-East to meet this PJM reserve margin criterion.

Summary Exhibit 2



Source: AEP Resource Planning

Major Drivers

Load

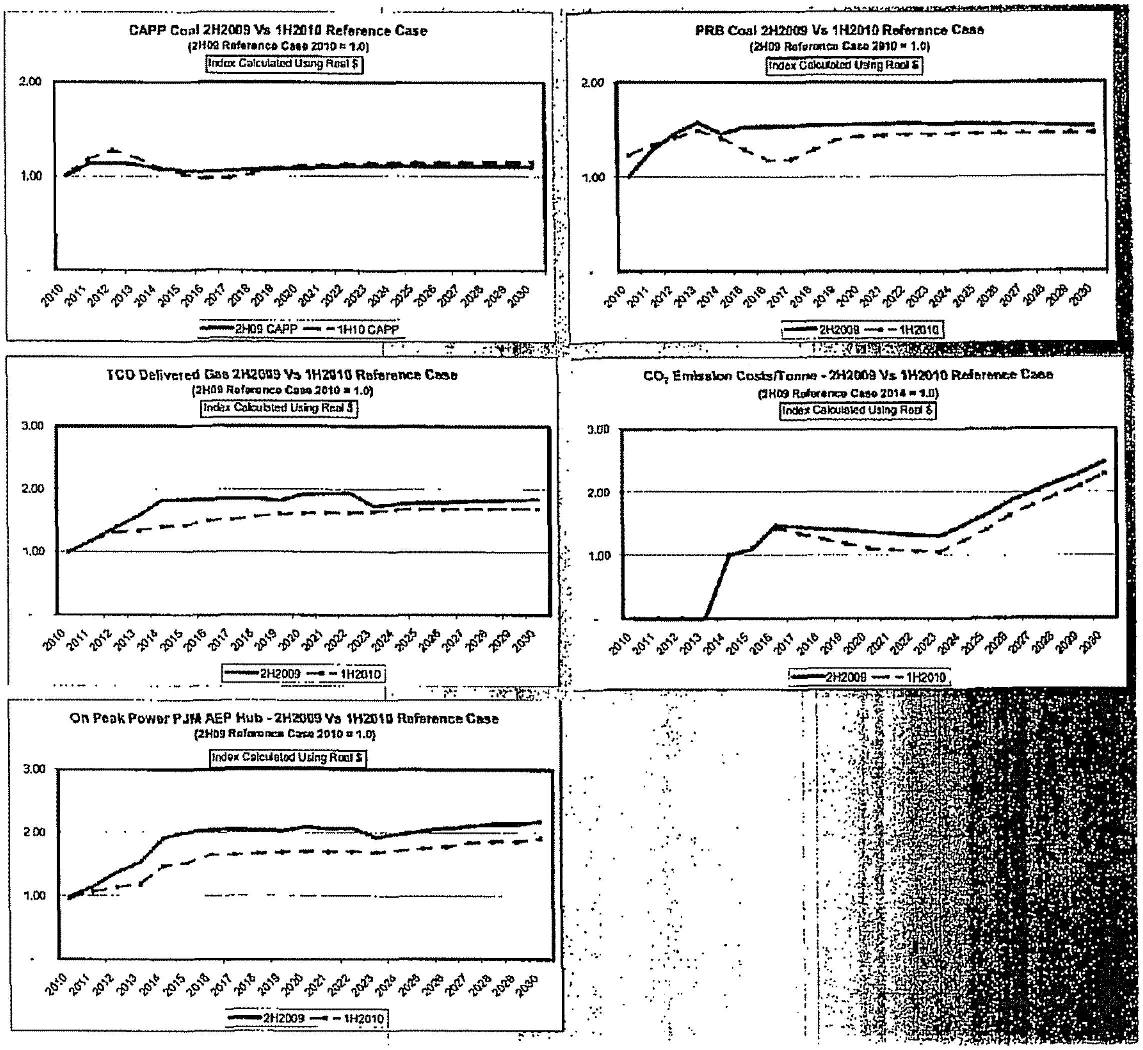
Anticipated load and peak demand is one of the chief underpinnings of the planning process. Over the 10-year Planning Period, the AEP-East region's internal demand profile has a 0.71% Compound Annual Growth Rate (CAGR). This equates to an approximate **150 MW per year increase** over the Planning Period if the load growth was uniform. This is considerably lower than the CAGR projected in the previous, 2009 IRP load forecast of 1.31 percent, or about 280 MW annually. This lower growth rate obviously delays the need for replacement capacity even with the prospect of accelerated AEP-East coal unit retirements.

Commodity Pricing

AEP updates its commodities forecast twice each year. The Fall of 2009 forecast (2H09 Forecast) was used as the basis for resource modeling in this IRP process. After comparing the 2H09 Forecast to the subsequent long term forecast prepared in the Spring of 2010 (1H10 Forecast), as shown in **Summary Exhibit 3**, it was apparent that the effects of the recently-revised pricing estimates were not significant in determining future resource additions and did not warrant a new resource evaluation. Note that with the economic recovery, prices for on-peak power, coal and natural gas will rise in real terms over the next 3 to 5 year period and then remain relatively stable.

Summary Exhibit 3

Commodity Price Comparison 2H09 to 1H10



Potential Carbon Legislation

There has been much activity and discussion in Congress regarding legislation to require reductions in GHG/CO_2 emissions. In this 2010 IRP it has been assumed that such legislated or regulated carbon restrictions will ultimately be established. The pricing assumptions and requirements for CO_2 used in this IRP were developed after the U.S. House passage of the Waxman-Markey Bill. Future IRPs will naturally reflect legislation (or regulation) that is enacted or developed after this report is issued. The driving planning assumptions around Climate Change in this 2010 IRP include substantive GHG/CO_2 reduction legislation effective *by 2014* with an economy-wide cap-and-trade regime effective in the same year. Although Waxman-Markey assumes a 2012 start-date, and more recent legislation introduced in the Senate ("Kerry-Lieberman" Discussion Draft) assumes a 2013 start-date, the assumption is that such comprehensive GHG/CO_2 legislation will not be approved by Congress this year and, as such, will not be effective until *at least* 2014.

Proposed EPA Rulemaking

The 2010 IRP considered potential future U.S. EPA rulemaking around HAPs. According to the AEP Environmental Services group, such federal rulemaking for HAPs could become effective by as early as the end of 2015 when a "command-and-control" policy could require all U.S. coal and lignite units to install Maximum Available Control Technologies (MACT) including (combined) Flue Gas Desulphurization (FGD), Selective Catalytic Reduction (SCR), as well as, potentially, Activated Carbon Injection (ACI) with fabric filter emissions control equipment for mercury and numerous other heavy metals, toxic compounds, and acid gases.

In addition, new rules on the handling and disposal of CCR are also being developed and could likewise be implemented as early as 2017, requiring significant additional capital investment in the coal fleet to convert "wet" flyash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to "dry" systems, plus build waste-water treatment facilities to address plant groundwater run-off. Further, the federal EPA has also recently issued proposed rulemaking to replace the former Clean Air Interstate Rules (CAIR) for sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and particulate matter (PM), which had previously been vacated by the federal courts. In lieu of a national cap-and-trade for those effluents, this "Transport Rule" would potentially establish *state-specific* emission budgets for SO_2 and both Annual and Seasonal (May-September) NO_X. In the AEP-East zone states (Indiana, Kentucky, Ohio, Virginia and West Virginia), such proposed Transport Rule emission reduction requirements are likewise contentious in that it would theoretically involve acceleration of already-planned environmental retrofits to as early as January, 2014; in-service dates that may be implausible to achieve.

In summary, the cumulative cost of complying with these collective emerging environmental rules could ultimately be hugely burdensome on the AEP-East Operating Companies and its customers. Therefore, such requirements, if formally established by EPA, could then also accelerate proposed retirement dates of any currently non-retrofitted coal unit in the AEP-East fleet as established within this 2010 IRP as discussed below.

Additional Potential Coal Unit Dispositions

An AEP-East unit disposition study was undertaken by an IRP Unit Disposition evaluation team involving numerous AEP functions. As in the past, the team's primary intent was to assess the relative composition and timing of potential unit retirements. As in previous reviews, the predominant focus in the East was again on the roughly 5,300 MW of older-vintage, less-efficient, non-environmental control-retrofitted (i.e., "Fully-Exposed") coal units in the AEP-East fleet.

As suggested above, in this 2010 IRP cycle review, the team considered financial implications of the potential (dispatch) cost impacts associated with CO_2 emissions, as well as cost to comply with assumed HAPs rulemaking. In addition, factors including PJM operational flexibility, emerging unit liabilities, and workforce/community impacts were considered when recommending the relative multi-tier profile of potential unit retirements.

It should be noted that the conclusions of this updated unit disposition study are for the expressed purpose of performing this overall long-term IRP analysis and reflect on-going and evolving disposition assessments. ***From a capacity perspective, no formal decisions have been made with respect to specific timing of any such unit retirements***, with the exception of those units that are identified in the stipulated Consent Decree related to the NSR litigation.

AEP has assumed for planning purposes that all of the "Fully-Exposed" coal units in the AEP-East fleet would be retired over the course of the decade under the notion that the implementation of any U.S. EPA HAPs and/or CCR rulemaking would be potentially "extended and staggered" beyond end-of 2015 in recognition of the national exposure (i.e., roughly 1/3 of U.S. coal units that are likewise fully-exposed and not likely to be retrofitted to achieve such rules.) Moreover, given the relative 'retrofit vs. retire' economics, it is further assumed that OPCo's ***Muskingum River Unit 5****—a relative newer, more thermally-efficient 600-MW coal unit—would likewise be retired in the mid-to-late Planning Period... for a total of nearly 6,000 MW of coal unit retirements.*[2]

Carbon Capture and Storage Technology

While the 2010 IRP does not include any coal-fired baseload additions, it does recognize that the existing fossil fleet will likely be subject to CO_2 emission reduction requirements in the future be it through legislated or regulated means. Therefore, the Plan includes the continued development and phase-in of Carbon Capture and Storage (CCS) at the (APCo) Mountaineer Plant as a practical, technology-advancing strategy. AEP has received partial funding from the U.S. Department of Energy (DOE) on the proposed Phase 2 (235-MW slipstream) CCS initiative at Mountaineer. Projects such as this one will position us well should legislation provide for "Bonus Allowances". Both the Waxman-Markey Bill and the (Draft) Kerry-Lieberman comprehensive climate change legislation in the U.S. Senate offer such "Bonus Allowance" provisions.

Assuming such CCS Bonus Allowances *are* available, this 2010 AEP-East IRP has also assumed that both the APCo Mountaineer Station and a unit at the OPCo Gavin Station (combined 2,600 MW) would have CCS fully-installed toward the end of the Planning Period in 2019-2020.

[2] For 2010 Plan purposes, other than Muskingum River U5, all other comparable AEP-East "Partially-Exposed" coal units not currently fully-retrofitted to meet either NSR Consent Decree or anticipated HAPs rulemaking requirements (Big Sandy Unit 2, Rockport Units 1&2, Conesville Units 5&6) are assumed to be retrofitted and would *continue operation* throughout the Study Period.

Peak Demand Response and Energy Efficiency

Recognizing the prospects of higher marginal or "avoided" costs, AEP initiatives to improve grid efficiency and install advanced metering, as well as a national groundswell focused on usage efficiency, the AEP-East 2010 IRP reflects approximately 415 MW of incremental peak demand reduction (above the 473 MW of interruptible load currently in place) by the end of 2011, growing to 1,213 by the end of 2014.

These incremental reductions in peak demand result from a suite of sources including:

- "Passive" demand reductions via customer-focused energy efficiency ("24/7"-type) programs (560 MW);
- "Active" demand response ("peak shaving"-type) program opportunities (600 MW); and
- unique utility infrastructure efficiency initiatives such as Integrated Volt/Var Control (IVVC) (53 MW).

Further, this Plan fully reflects legislative and regulatory mandated levels of AEP-East Operating Company energy efficiency and demand response in Ohio, Indiana and Michigan.

Wind and Other Renewable Resources

Along with the prospects of comprehensive GHG/CO_2 legislation—or even as a "carve-out" as part of any potential Energy Bill that could be contemplated in Congress—the possible introduction of a Federal Renewable Portfolio Standard (RPS) has resulted in the planned AEP system-wide addition of 2,000 MW of renewable resources by approximately mid-decade, or end-of-2014. Note that this represents an approximate 3-year shift from prior (2009 IRP) planned commitments of 2,000 MW of System-wide renewable resources by the end of *2011*; however, as recent unfavorable regulatory decisions in both Virginia and Kentucky surrounding cost recovery of planned wind purchase transactions has resulted in this "extension" of that prior goal.

The largest portion of these additions (about 1,100 MW nameplate of, predominantly, wind resources) is assumed to be applicable to AEP-East. Placed in addition to current and planned AEP-SPP region affiliates—Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO)—long-term wind development/purchases as well as economically-screened biomass co-firing opportunities, the overall AEP System is positioned to achieving a ***target of 10 percent of energy sales from renewable sources by the end of the IRP Planning Period (2020)***, again consistent with Ohio Substitute S.B. 221 and other state-mandated renewable requirements in Michigan, West Virginia, Oklahoma and Texas.

Emerging Technologies

AEP is committed to pursuing emerging technologies that fit into the capacity resource planning process including, among others, fuel cells, solar, energy storage as well as "smart-grid" enabling meters and distribution infrastructure. These largely *distributed* technologies, while currently expensive relative to traditional demand and supply options—and in consideration of AEP-East's current capacity and energy "length" in PJM—have the capability to evolve into far more common and accepted resource options as costs come down and performance/efficiencies continue to improve. For each of these options, both the technology and associated costs will continue to be very closely monitored for inclusion in future annual planning cycles.

As an example, the 2010 AEP-East IRP includes the addition of IVVC technology into the distribution system infrastructure which will reduce voltages and, hence customer usage behind the meter. This technology therefore helps cost-effectively mitigate the need for new capacity and reduces energy requirements resulting in reduced emissions.

Portfolio Risk Analysis

Given the uncertainties facing AEP in the future, a number of diverse resource portfolios were analyzed under a wide range of future commodity pricing scenarios. This allowed the resource planners to evaluate whether near-term decisions may adversely impact future costs to customers. The portfolios that were evaluated include accelerated near-term coal unit retirements (over-and-above Muskingum River U5), additional DR/EE and renewable resources, the addition of nuclear capacity, as well as various combinations of these end-states under various commodity pricing scenarios. This exercise provided intelligence in establishing the final recommended plan.

AEP-East Recommended Plan: 2011-2020

(Including AEP-East Company Responsibility)

- ✓ Complete the 540 MW Dresden Combined Cycle Facility by 2013 (AEG-APCo)
- ✓ Retire 5,930 MW of coal-fired generating units over the period: 2012-to-2019 (Various), including the 600 MW Muskingum River Unit 5 (OPCo)
- ✓ As part of the life extension component replacement program required under the 20-year operating license extension received in August 2005, uprate the D.C. Cook Units 1 and 2 by 417 MW over the 2014 to 2018 timeframe (I&M)
- ✓ Construct or acquire peaking duty cycle (e.g., Combustion Turbine) capacity: 314 MW by 2017 (APCo), and an additional 314 MW by 2018 (KPCo/APCo) for both ultimate capacity *and* anticipated system reliability/restoration ("Black Start") requirements
- ✓ Purchase or construct an *additional* 1,600 MW (nameplate) of wind generation by 2020 (Various), over-and-above the 626 MW already in operation, to achieve both state-mandated renewable requirements (OH, MI, WVa) as well as contribute to a 10% (of retails sales) "target" by 2020
- ✓ Co-fire with biomass feedstock at existing units, or acquire the "equivalent" of approximately 150 MW of dedicated biomass generation by 2018 (CSP, OPCo, & APCo)
- ✓ Purchase or construct an additional 215 MW (nameplate) of solar generation for the AEP-Ohio Companies (CSP and OPCo) in order to achieve "solar-specific" renewable mandates set forth under Ohio S.B. 221, in addition to the 10 MW solar (Wyandot) PPA already in operation
- ✓ Continue the Carbon Capture and Storage (CCS) project at Mountaineer (APCo) and ultimately fully install CCS at Mountaineer and Gavin Unit 1 (OPCo) by 2020 [3]
- ✓ Implement Energy Efficiency programs totaling over 6,000 GWh (868 MW of attendant "passive" Demand Response) by 2020 across all AEP-East states/companies to meet either legislative or regulatory mandated (OH, MI, IN) requirements or, incrementally, known/anticipated initiatives in non-mandated states
- ✓ Implement "Active" Demand Response initiatives totaling 600 MW by 2015 (Various)
- ✓ Upgrade the distribution system with IVVC technology, reducing (peak) demand by 106 MW and customer energy usage totaling roughly 500 GWh by 2018 (Various)

[3] Any CCS implementation beyond the current Mountaineer "Phase 2" (235-MW slipstream) project would be subject to qualification and receipt of cost-offsetting "(CO_2) Bonus Allowances" emanating from potential comprehensive Climate Change legislation currently before the U.S. Congress.

The following **Summary Exhibit 4** offers a view of the 2010 AEP-East IRP:

Summary Exhibit 4

"Hybrid" Portfolio:

Reflective of April-10 Load Forecast [(a)]

AEP-East

Period	Pln Yr	(b) Capacity (Retire)	CCS Retrofit Unit	CCS Retrofit Capac	CCS Retrofit Derate	Efficiency: Dem (c) Response ("Active"DR)	Efficiency: Energy (a) Efficiency ("Passive"DR)	Efficiency: Infrastruc. (e.g. IVVC)	Renewable (Nameplate) (d): Wind	Renewable (Nameplate) (d): (e) Biom	Renewable (Nameplate) (d): Solar	Thermal Resources (summer rating)	Oper Co. Assigned		PJM-CLR Capacity Position (above PJM IRM min) (MW)
(10-Year) Planning Period	2010	(440)					16		451		10		⇩	(f)	1,240
	2011					100	90		101	44	10			(g)	1,292
	2012	(560)				100	93		100		11			(h)	1,113
	2013					150	102		100	25	10	(Dresden) CC-540	APCo		2,038
	2014	(395)				150	112	19	300	25	26	Cook2 (Ph1)-45	I&M		2,720
	2015	(925)	MT	235	(58)	100	89	31	400		27	Cook1&2 (Ph1&2)-168	I&M		2,188
	2016	(1,175)					67	17	250	(44)	26	Cook1 (Ph2)-68	I&M		1,934
	2017	(675)					59	16	150		26	Cook2 (Ph3)-68 NG Peaking-314	I&M APCo	(i)	1,988
	2018	(400)					48	17	50	100	26	Cook1 (Ph3)-68 NG Peaking-314	I&M APCo/KPCo	(j)	1,856
	2019	(1,373)	MT	1,065	(137)		88		100		26				343
	2020		GV1	1,300	(195)		104		150		27				399
Study Period	2021						72		100	50	29	NG Peaking-314	APCo/KPCo	(k)	388
	2022		AM3	1,300	(195)		51		100		45				359
	2023						35		200			NG Intermediate-611	APCo		420
	2024						21		150	100	45				403
	2025						16		150						232
	2026						5		150		20	NG Intermediate-611	APCo		677
	2027						1		150	50					523
	2028								100		25				403
	2029														204
	2030										31	NG Peaking-314	APCo		304
				3,900				"Nameplate"	3,252	350	420				
	Cumul.	(5,943)			(586)	600	1,069	100	423	50	160	3,435			

2010-2030
Net Addition
(692)

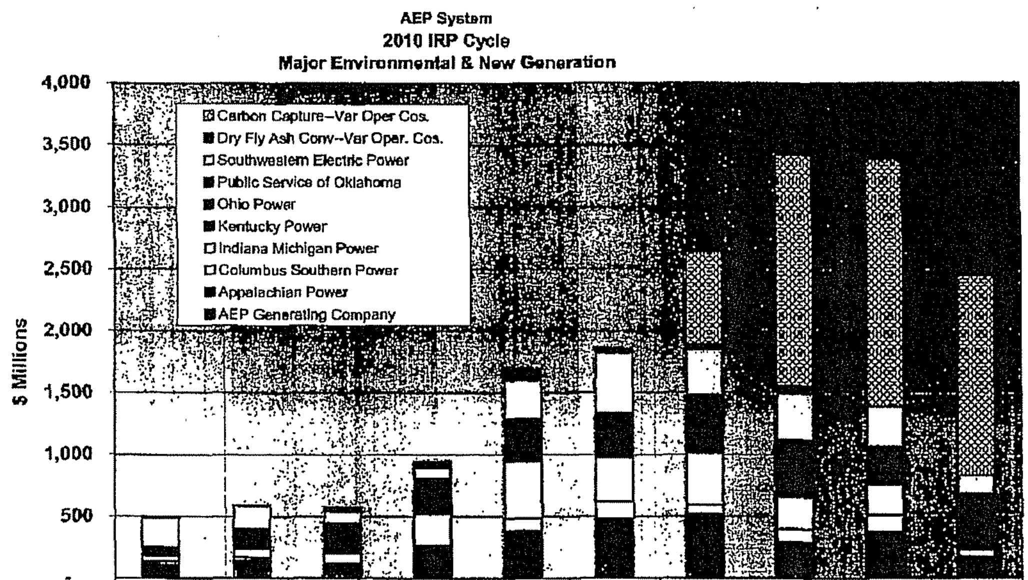
(a) *Underlying Peak Demand as well as "Passive" (Energy Efficiency) Demand Reduction levels are per AEP-Economic Forecasting "April '10" **Forecast** (Note: includes mandated EE requirements in OH, IN, MI)*
(b) Reflects PJM planning year that capacity is de-committed in PJM-FRR
(c) "Active" DR (i.e. demand response curtailment programs/tariffs) only
(d) 13% of wind nameplate and 38% of solar nameplate can be "counted" as PJM capacity (per *initial* PJM criteria)
... Assumes 'full-year' energy impact (i.e. *in-service* by 12/31 of Year -1)
(e) Only 25 MW '2013' and '2014' biomass represents incremental capacity via a dedicated biomass facility (assumed AEP-Ohio PPA)...
... balance represents 'equivalent' biomass-sourced energy via co-firing.... through, initially, *existing* AEP-Ohio units
(f) "2010" wind: Fowler Ridge I, II & II (350 MW: AP, I&M, CSP, OP); Grand Ridge I & III (100.5 MW: AP)... "2010" solar: Wyandotte (10MW: CSP, OPCo)
(g) "2011" wind: Beech Ridge (100.5 MW: AP) only... i.e., assumes Lee-Dekalb (100 MW: KP) eliminated as KPSC denied recovery and, as per contract, it may then be voided
(h) "2012" wind: Represents 'Unidentified' 100-MW wind designated to AEP-Ohio companies to be in-keeping w/ requirements of S.B. 221
(i) Assumes advanced four-years (from 2021) to provide Black-Start requirements @ TC area
(j) " " three-years (from 2024) to provide Black-Start requirements @ KM area
(k) " " three-years (from 2021) to provide Black-Start requirements @ SP area

Source: AEP Resource Planning

Plan Impact on Capital Requirements

This Plan includes new capacity resource additions, as described, as well as unit uprates and assumed environmental retrofits. Such generation additions require a *significant* investment of capital. Some of these projects are still conceptual in nature, others do not have site-specific information to perform detailed estimates; however, it is important to provide an order of magnitude cost estimate for the projects included in this plan. As some of the initiatives represented in this plan span both East (and West) AEP zones, this **Summary Exhibit 5** includes estimates for such projects over the entire AEP System.

Summary Exhibit 5



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Carbon Capture–Var Oper Cos	-	-	-	-	-	-	746	1,861	2,000	1,618
Dry Fly Ash Conv--Var Oper. Cos.	-	12	34	52	86	28	43	62	-	-
Southwestern Electric Power	236	187	95	87	320	488	366	377	330	142
Public Service of Oklahoma	6	9	0	5	127	258	366	364	172	299
Ohio Power	40	43	68	77	65	28	30	36	62	63
Kentucky Power	23	104	174	207	145	75	76	56	65	76
Indiana Michigan Power	47	70	81	257	458	360	418	281	252	19
Columbus Southern Power	21	27	20	25	100	141	69	103	133	65
Appalachian Power	107	52	66	185	248	222	141	63	122	165
AEP Generating Company	5	90	37	50	140	253	380	232	252	18

Source: AEP Resource Planning

It is important to reiterate the capital spend level reflected on the **Summary Exhibit 5** is "incremental" in that it does not include "Base"/business-as-usual capital expenditure requirements of the generation facilities or transmission and distribution capital requirements. Achieving this additional level of expenditure will therefore be a significant challenge going-forward and would suggest the Plan itself *will remain under constant evaluation and is subject to change* as, particularly, AEP's system-wide and operating company-specific "Capital Allocation" processes continue to be refined. Also, while the spend level includes cost to install Carbon Capture equipment, these projects are included <u>only</u> under the assumption that any comprehensive GHG/CO_2 bill requiring significant reductions in CO_2 emissions will include a provision to receive credits or allowances that would largely offset the cost of such equipment.

Conclusions

The recommended AEP-East capacity resource plan reflected on **Summary Exhibit 4** **provides the lowest reasonable cost solution through a combination of traditional supply, renewable and demand-side resources.** The most recent (April 2010) "tempered" load growth, combined with the completion of the Dresden natural gas-combined cycle facility, additional renewable resources, increased DR/EE initiatives, and the proposed capacity uprate of the Cook Nuclear facility allow AEP-East region to meet its reserve requirements until the 2018-2019 timeframe, at which point modeling indicates new peaking capacity will be required. Other than the aforementioned D.C. Cook uprate, no new baseload capacity is required over the 10-year Planning Period.

The Plan also positions the AEP-East Operating Companies to achieve legislative or regulatory mandated state renewable portfolio standards and energy efficiency requirements, and sets in place the framework to meet potential CO2 reduction targets and emerging U.S. EPA rulemaking around HAPs and CCR at the intended least reasonable cost to its customers.

The resource planning process is becoming increasingly complex given these uncertainties as well as spiraling technological advancements, changing economic and other energy supply fundamentals, uncertainty around demand and energy usage patterns as well as customer acceptance for embracing efficiency initiatives. All of these uncertainties necessitate flexibility in any on-going plan. Moreover, the ability to invest in capital-intensive infrastructure is increasingly challenged in light of current economic conditions, and the impact on the AEP-East Operating Companies' customer costs-of-service/rates will continue to be a primary planning consideration.

Other than those initiatives that fall within some necessary "actionable" period over the next 2-3 years, this long-term Plan is also not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative and regulated proposals to control greenhouse gases and numerous other hazardous pollutants… all of which will likely result in either the retirement or costly retrofitting of all existing AEP-East coal units.

Finally, bear in mind that the planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported here reflects, to a large extent, assumptions that are clearly subject to change. In summary, it represents a very reasonable "snapshot" of future requirements at this particular point in time.

1.0 Introduction and Planning Issues

This report documents the processes and assumptions required to develop the recommended integrated resource plan (IRP or the "Plan") for the AEP-East System. The IRP process consists of the following steps:

- Describe the company, the resource planning process in general (**Section 1**).
- Describe the implications of current issues as they relate to resource planning (**Section 2**).
- Identify current supply resources, including projected changes to those resources (e.g. de-rates or retirements), and transmission system integration issues (**Section 3**).
- Provide projected growth in demand and energy which serves as the underpinning of the plan (**Section 4**).
- Combine these two projected states (resources versus demand) to identify the need to be filled (**Section 5**).
- Describe the analysis and assumptions that will be used to develop the plan such as future resource options (**Section 6**), evaluation of demand side measures (**Section 7**), and fundamental modeling parameters (**Section 8**).
- Perform resource modeling and use the results to develop portfolios, including the selection of the ultimate "Hybrid Plan" (**Section 9**).
- Utilize risk analysis techniques on selected portfolios (**Section 10**).
- Present the findings and recommendations, plan implementation and, finally, plan implications on AEP East operating companies (**Sections 11 and 12**).

1.1 IRP Process Overview

This report presents the results of the IRP analysis for the AEP East (PJM) zone of the AEP System, covering the ten year period 2011-2020 (Planning Period), with additional planning modeling and studies conducted through the year 2030 (extended Study Period). The information presented in this IRP includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply and demand side resources.

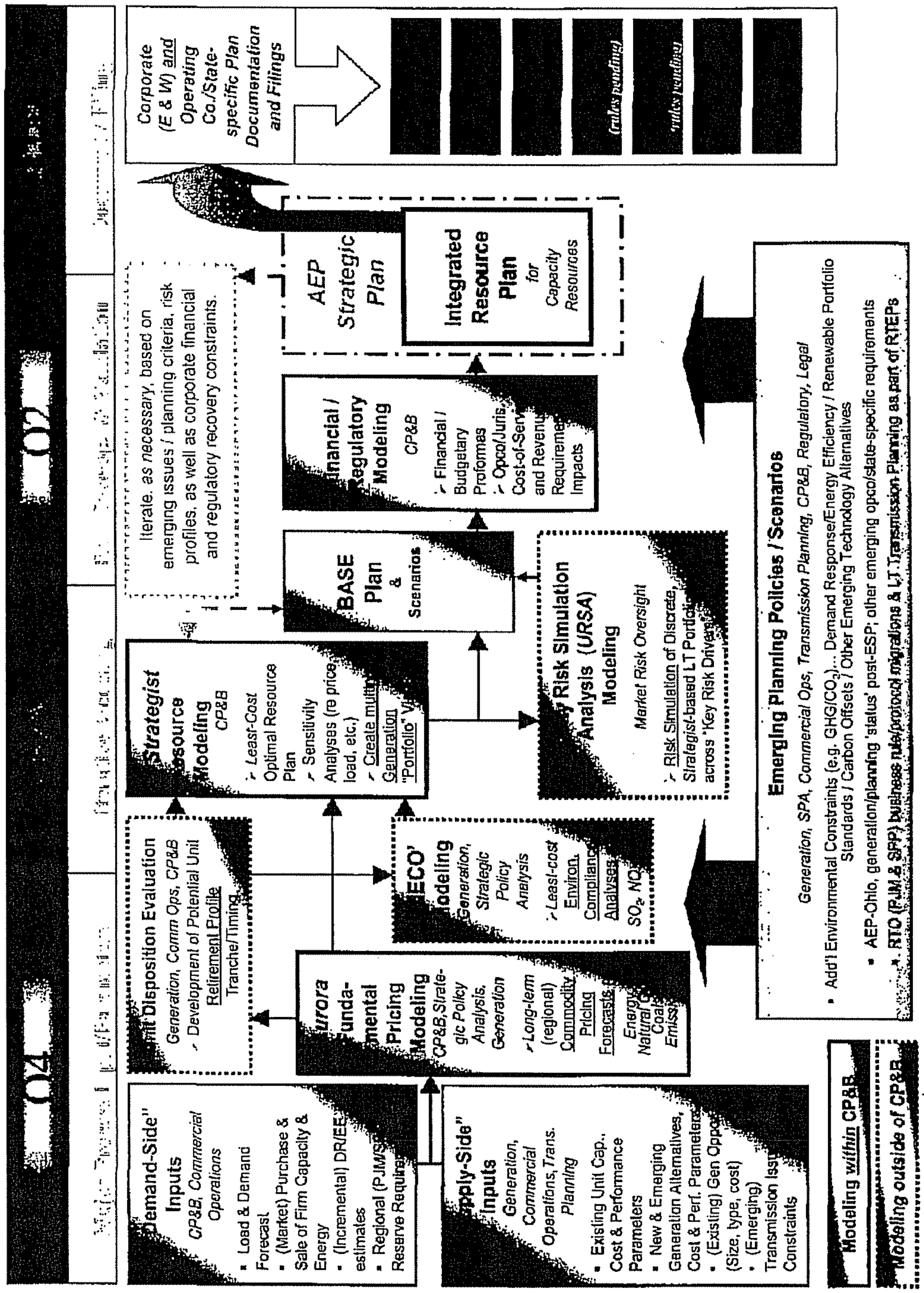
In addition to the need to set forth a long-term strategy for achieving regional reliability/reserve margin requirements, capacity resource planning is critical to AEP due to its impact on:

- **Capital Expenditure Requirements**
- **Rate Case Planning**
- **Integration with other Strategic Business Initiatives e.g.,** corporate sustainability goals, environmental compliance, transmission planning, etc

The goal of the IRP process is to identify the ***amount, timing*** *and* ***type*** *of resources required to ensure a reliable supply of power and energy to customers at the lowest reasonable cost.*

The IRP process is displayed graphically in **Exhibit 1-1**.

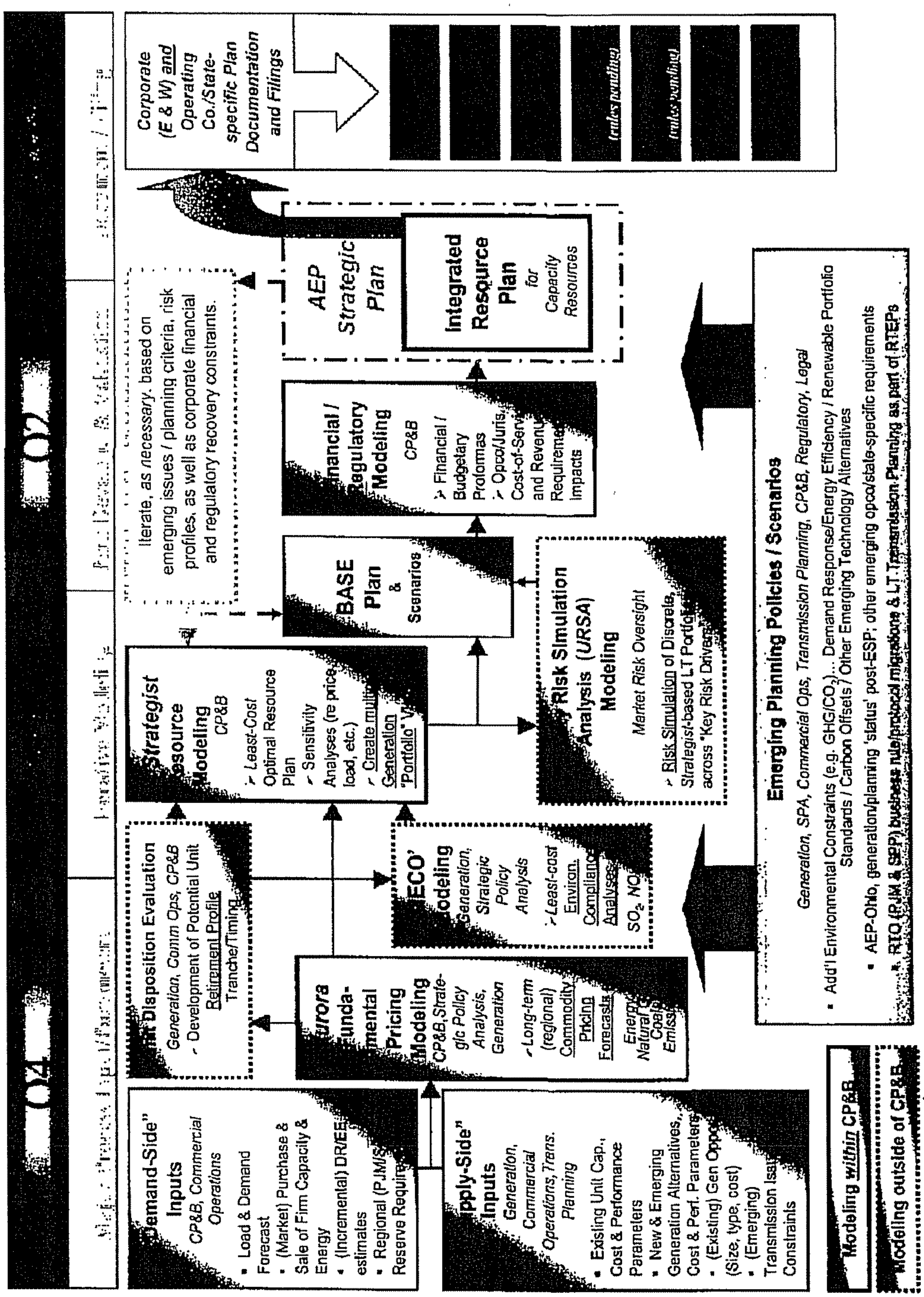
Exhibit 1-1: IRP Process Overview



Source: AEP Resource Planning

AMERICAN ELECTRIC POWER

Exhibit 1-1: IRP Process Overview

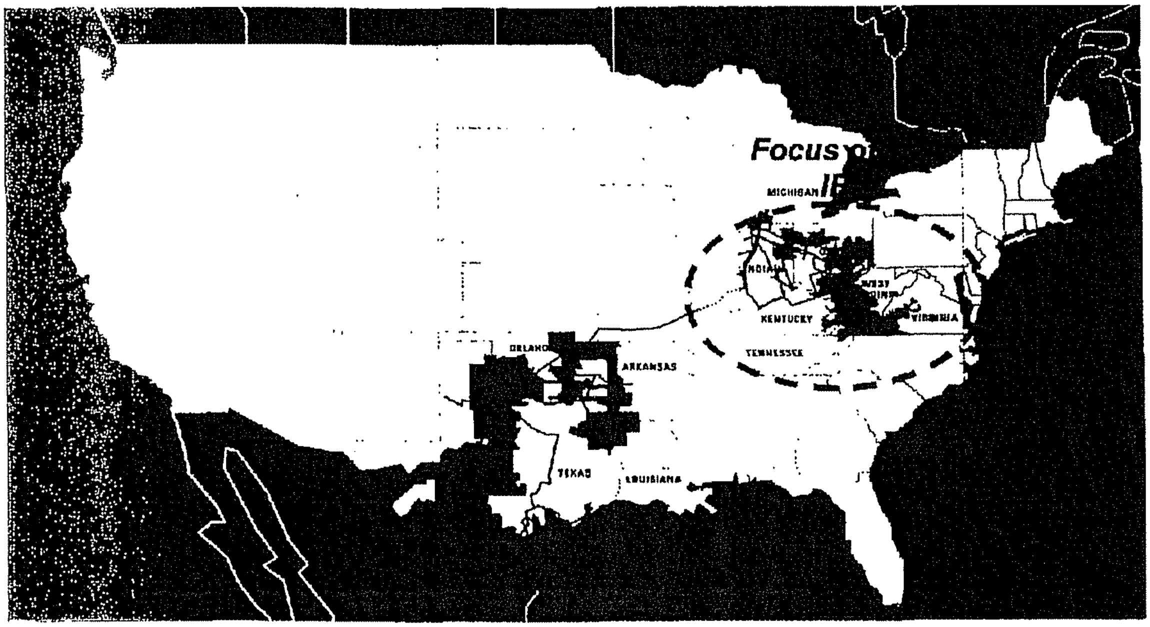


Source: AEP Resource Planning

1.2 Introduction to AEP

AEP, with more than five million American customers and serving parts of 11 states, is one of the country's largest investor-owned utilities. The service territory covers 197,500 square miles in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia (see **Exhibit 1-2**).

Exhibit 1-2: AEP System, East and West Zones



Source: AEP Internal Communications

AEP owns and/or operates 80 generating stations in the United States, with a capacity of approximately 38,000 megawatts. AEP's customers are served by one of the world's largest transmission and distribution systems. System-wide there are more than 39,000 circuit miles of transmission lines and more than 214,000 miles of distribution lines.

AEP's operating companies are managed in two geographic zones: Its eastern zone, comprising Indiana Michigan Power Company (I&M), Kentucky Power Company (KPCo), Ohio Power Company (OPCo), Columbus Southern Power Company (CSP), Appalachian Power Company (APCo), Kingsport Power Company (KgP), and Wheeling Power Company (WPCo); and its western zone, which, for resource planning purposes within the Southwest Power Pool (SPP), comprises the Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO).[4] CSP and OPCo operate as a single business unit called AEP-Ohio.

[4] Both KgP and WPCo are non-generating companies purchasing all power and energy under FERC-approved wholesale contracts with affiliates APCo and OPCo, respectively. AEP also has two operating companies that reside in the Electric Reliability Council of Texas (ERCOT), AEP Texas North Company (TNC) and Texas Central Company (TCC). These companies are essentially "wires" companies only, as neither owns nor operates regulated generating assets within ERCOT.

Other than a discussion of the requirements of the FERC-approved AEP System Integration Agreement (SIA), this document will only address 2010 resource planning for the AEP-East zone. Planning for affiliates PSO and SWEPCO operating in SPP will be communicated in a separate IRP document.

1.2.1 AEP-East Zone–PJM:

AEP's eastern zone ("AEP-East" or "AEP-PJM") operating companies collectively serve a population of about 7.2 million (3.26 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The internal (native) customer base is fairly diversified. In 2009, residential, commercial, and industrial customers accounted for 28.4%, 22.2%, and 35.9%, respectively, of AEP-East's total internal energy requirements of 130,519 GWh. The remaining 13.5% was supplied for street and highway lighting, firm wholesale customers, and to supply line and other transmission and distribution equipment losses.

AEP-East experienced its historic peak internal demand of 22,411 MW on August 8, 2007. The historic winter peak internal demand, 22,270 MW, was experienced on January 16, 2009. AEP-East reached its all-time peak total demand of 26,467 MW, including sales to nonaffiliated power systems, on August 21, 2003.

1.2.2 AEP-East Pool

The 1951 AEP Interconnection Agreement (AEP Pool) was established to obtain efficient and coordinated expansion and operation of electric power facilities in its eastern zone. This includes the coordinated and integrated determination of load and peak demand obligations for each of the member companies. Further, member companies are expected to "rectify or alleviate" any relative capacity deficits of an extended nature to maintain an "equalization" over time. As such, capacity planning is performed on an AEP-East integrated basis, with capacity assignments made to the pool members based on their relative deficiency within the Pool.

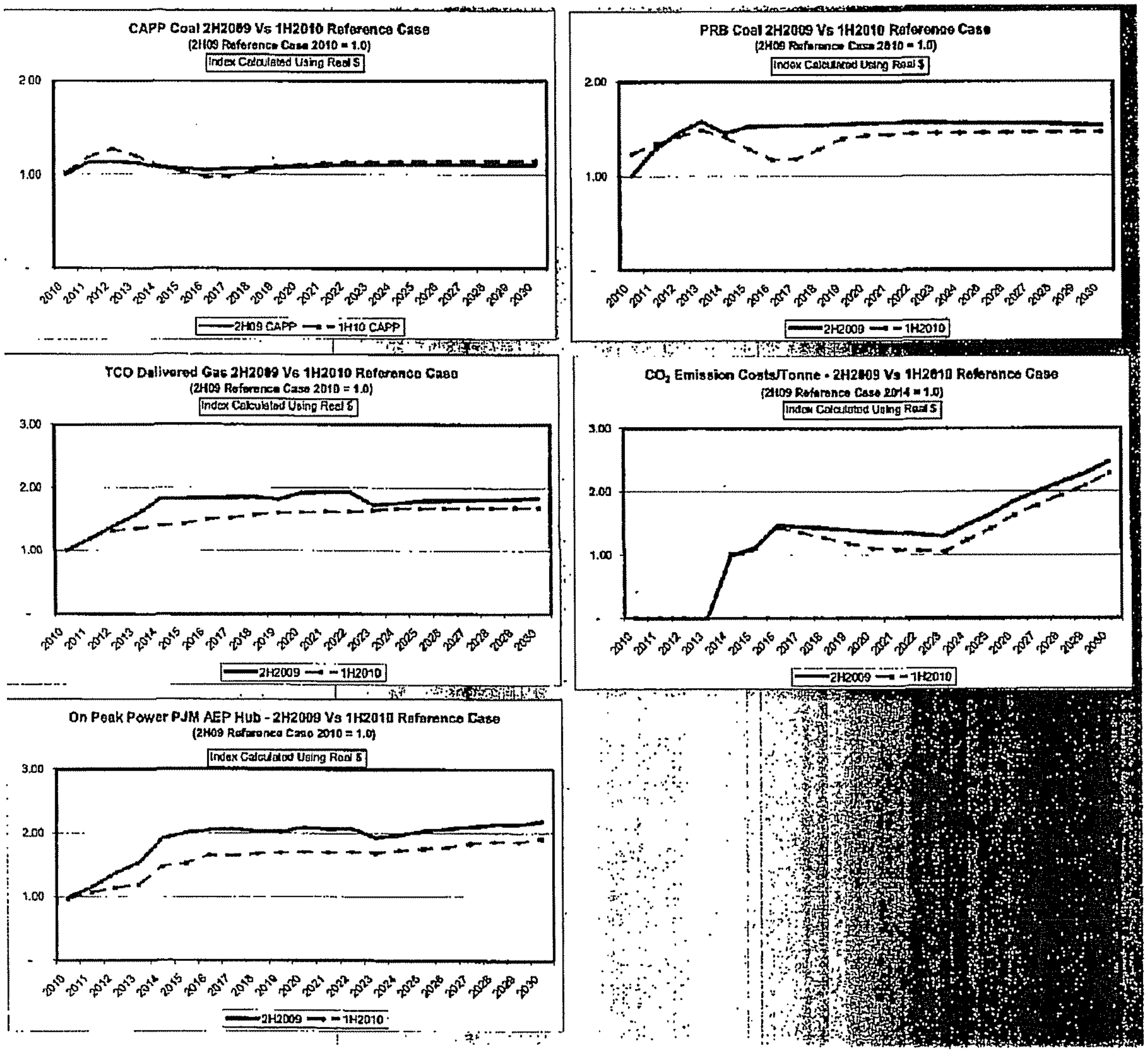
1.2.3 AEP System Interchange Agreement (East and West)

The 2000 System Interchange Agreement (SIA) among AEPSC - as agent for the AEP-East operating companies, and Central and Southwest Services, Inc. (CSW) – including the AEP-West companies - was designed to operate as an umbrella agreement between the FERC-approved 1997 Restated and Amended CSW Operating Agreement for its western (former CSW) operating companies and the FERC-approved 1951 AEP Interconnection Agreement for its eastern operating companies. The SIA provides for the integration and coordination of AEP's eastern and western companies' zones. In that regard, the SIA provides for the transfer of capacity and energy between the AEP-East zone and the AEP-West zone under certain conditions. Since the inception of the SIA, AEP has continued to reserve annually, the transmission rights associated with a prescribed (up to) 250 MW of capacity from the AEP-East zone to the AEP-West zone.

1.3 Commodity Pricing

AEP updates its commodities forecast twice each year. The Fall of 2009 forecast (2H09 Forecast) was used as the basis for resource modeling in this IRP. After comparing the 2H09 Forecast to the subsequent long term forecast prepared in the Spring of 2010 (1H10 Forecast), as shown in Exhibit 1-3, it was apparent that the effects of the revised pricing estimates were not significant in determining future resource additions and did not warrant a new resource evaluation.

Exhibit 1-3 Comparison of 2H09 and 1H10 Commodity Forecasts



2.0 Industry Issues and Their Implications

2.1 Environmental Rulemakings and Legislation

This 2010 IRP considered existing and potential U. S. Environmental Protection Agency (EPA) rulemakings as well as proposed legislation controlling CO_2 emissions. Emission compliance requirements have a major influence on the consideration of supply-side resources for inclusion in the IRP because of their potential significant effects on both capital and operational costs. The cumulative cost of complying with these rules could ultimately have an impact on proposed retirement dates of any currently non-retrofitted coal and lignite units.

2.1.1 Mercury and Hazardous Air Pollutants Regulation

The Clean Air Mercury Rule (CAMR) was issued by the U.S. EPA in May 2005. The rule instituted a cap-and-trade program to limit emissions of mercury from coal-fired power plants across the United States. The CAMR required coal-fired power plants to begin monitoring mercury emissions on January 1st, 2009, with cap and trade emission reductions required beginning on January 1st, 2010. However, the CAMR was appealed by various entities, and in February 2008 the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating the CAMR.

With the vacatur of CAMR and the completion of the appeals process, the U.S. EPA has announced its intent to develop a new regulatory program for mercury emissions and other Hazardous Air Pollutants, including, among others, arsenic, selenium, lead, cadmium and various acid gases (collectively "HAPs" or "HAPs rulemaking") under the Maximum Achievable Control Technology (MACT) provision of the Clean Air Act. A MACT rule for HAPs will establish regulations that are "command and control"; meaning that it will not be a cap-and-trade program and that unit specific controls or emission rates will need to be met. The EPA has set a deadline for a proposed MACT rule to be issued for public review and comment in March 2011 and a final rule to be issued in November 2011. This rule is expected to take effect as early as December 2015. However, the MACT standards for HAPs has not been established, and the requirements for each unit will not be tentatively known until a proposed rule is issued and will not be definitively known until a final rule is issued late next year.

Although not definitively known, AEP Engineering Project and Field Services (EP&FS) and AEP Environmental Services attempted to identify reasonable proxies for MACT at each AEP coal unit. For the most part, some combination of Flue Gas Desulphurization (FGD) and Selective Catalytic Reduction (SCR), or Activated Carbon Injection (ACI) with fabric filter fugitive dust collection systems would likely be required for compliance.

2.1.2 Coal Combustion Residuals (CCR) Regulation

CCRs are the materials that result from combusting coal, and can include bottom ash, fly ash, and byproduct created from FGD systems capturing SO_2 from flue gas. Currently CCRs are classified as non-hazardous waste. Disposal of these materials is currently regulated at the state level. However, the U.S. EPA is developing a new regulatory program that will move regulation to the Federal level to ensure greater consistency across the country on disposal practices. A draft CCR disposal rule was issued in mid-2010. A final rule is expected in roughly a year, or mid-2011. The EPA has indicated it may regulate disposal of these materials as a special class of non-hazardous waste, or potentially as a hazardous waste. Either approach will result in more restrictive disposal requirements than currently exist.

2.1.3 Transport Rule

On July 6, 2010 the U.S. EPA proposed a Transport Rule to replace the 2005 Clean Air Interstate Rule (CAIR) which was vacated in 2008 by the U.S. Court of Appeals for the District of Columbia. The Transport Rule will require 31 states and the District of Columbia to reduce power plant emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X). The emission reductions will be state specific with limited allowance trading opportunity, and will become effective at an intermediate level in 2012, then at a final, more restrictive level in 2014. The emission reductions will be relative to a 2005 base year level. Each state will be required to develop source (plant) specific targets.

Once the Transport Rule is finalized and source specific targets are communicated, an action plan can be established to comply with this requirement. AEP's expectation is that this rule may influence the timing of certain FGD retrofits, plant operations, and/or unit retirements. However, given that AEP must operate within a previously established New Source Review (NSR) Consent Decree "cap" for NO_X and SO_2, and also retrofits or retire certain units by specific dates, the incremental Transport Rule compliance measures are not expected to significantly change the resource plan established in this report.

2.1.4 New Source Review—Consent Decree.

In December, 2007 AEP entered into a settlement of outstanding litigation around NSR compliance. Under the terms of the settlement, AEP will complete its environmental retrofit program on its operated Eastern units, operate those units under a declining annual cap on total SO_2 and NO_X emissions and install additional control technologies at certain units. The most significant additional control projects involve installing FGD and SCR systems at nine AEP-East coal fired units (Amos 1-3, Big Sandy 2, Cardinal 1, Conesville 4, Muskingum River 5 and Rockport 1 and 2) over an 11 year period beginning in 2009.

2.1.5 Carbon and Greenhouse Gas (GHG) Legislation

The electric utility industry, as a major producer of CO_2, will be significantly affected by any GHG legislation. The push towards federal climate change legislation is continuing within Congress. The Waxman-Markey "American Climate and Energy Security Act of 2009" was approved by the House of Representatives in June 2009, but was not followed up with comparable legislation being approved by the U.S. Senate. In December 2009 the U. S. EPA issued a finding that GHG from industry, vehicles, and other sources represent a threat to human health and the environment. In June 2010 the Senate voted 53-47 to reject an attempt to block the U.S. EPA from imposing new limits on carbon emissions. This defeat is seen as providing momentum to climate legislation efforts. Climate change legislation currently in the U.S. Senate is being sponsored by Senators Kerry and Lieberman. In most respects this draft legislation comports with the cap-and-trade provisions of the Waxman-Markey Bill.

With climate legislation on the horizon, the Company has embarked on an initiative to advance carbon capture technology to a commercial scale. In March 2007, AEP signed agreements with world-renowned technology providers for carbon capture and storage. A "product validation facility" has been constructed at the Mountaineer Plant in West Virginia and successfully began operation in the fall of 2009.

The carbon capture and storage equipment (CCS) operating on AEP's 1,300 MW Mountaineer Plant is a 20 MW (electric) product validation. It is designed to capture approximately 100,000 metric tons of CO_2 per year over a four to five year period; the CO_2 is being stored in deep geologic reservoirs. AEP now plans to scale up the Mountaineer Chilled Ammonia Process (CAP) to capture CO2 from a 235 MWe slip stream and has been awarded $336 million in funding from the U.S. Department of Energy. The expectation is for the commercial scale technology project to have a 90% capture rate of approximately 1.5 million tons of CO_2 per year and be online in 2015.

Utility applications of CCS technologies continue to be developed and tested, and as such are not yet commercially available on a large scale. However, given the focus on the advancement and associated cost reduction of such technologies, it is likely to become both available and cost-effective at some point over the IRP's longer-term planning horizon (through 2030). However, this is very dependent on the type of federal climate legislation that is passed and the degree to which there is financial support for CCS technology in such legislation. Assuming carbon capture and storage becomes commercially viable weight must be given to the options (and generating facilities) that are most readily adaptable to this technology

2.2 Additional Implications of Environmental Legislation – Unit Disposition Analysis

An AEP-East unit disposition study was undertaken by an IRP Unit Disposition evaluation team involving numerous AEP functional disciplines including: Fossil & Hydro Operations, Engineering, Project & Field Services (EP&FS), Environmental Services, Fuel Emissions Logistics (FEL), Commercial Operations, Transmission Planning, and Resource Planning. This fourth quarter 2009 effort was a follow-up to earlier studies that have been performed annually since 2005. As before, the team's primary intent was to assess the relative composition and timing of potential unit retirements. As in previous reviews, the initial focus was on the older-vintage, less-efficient, uncontrolled coal units in the AEP-East fleet. Factors including PJM operational flexibility, emerging unit liabilities, and workforce/community factors were considered when recommending the relative profile of potential unit retirements. In this 2010 IRP cycle review the team also considered the implications of the potential (dispatch) cost impacts associated with CO_2 emissions, as well as cost to comply with assumed emerging HAPs and CCR rulemaking on, particularly, the relatively newer and reasonably-thermally efficient uncontrolled super-critical coal units operating in the AEP-East fleet.

For instance, according to the AEP Environmental Services group, such federal rulemaking for HAPs could become effective by as early as the end of 2015 when a "command-and-control" policy could require all U.S. coal and lignite units to install mercury and heavy metals/toxins control technologies including (combined) FGD, SCR, as well as, potentially, ACI with fabric filter emissions control equipment. New rules on the handling and disposal of CCRs could likewise be implemented as early as 2017, requiring additional investment in the coal fleet to convert "wet" fly ash and bottom ash disposal equipment and systems — including attendant landfills and ponds — to "dry" systems. The cumulative cost of complying with these rules will most certainly require additional analysis and may have an impact on proposed retirement dates of any currently non-retrofitted coal unit.

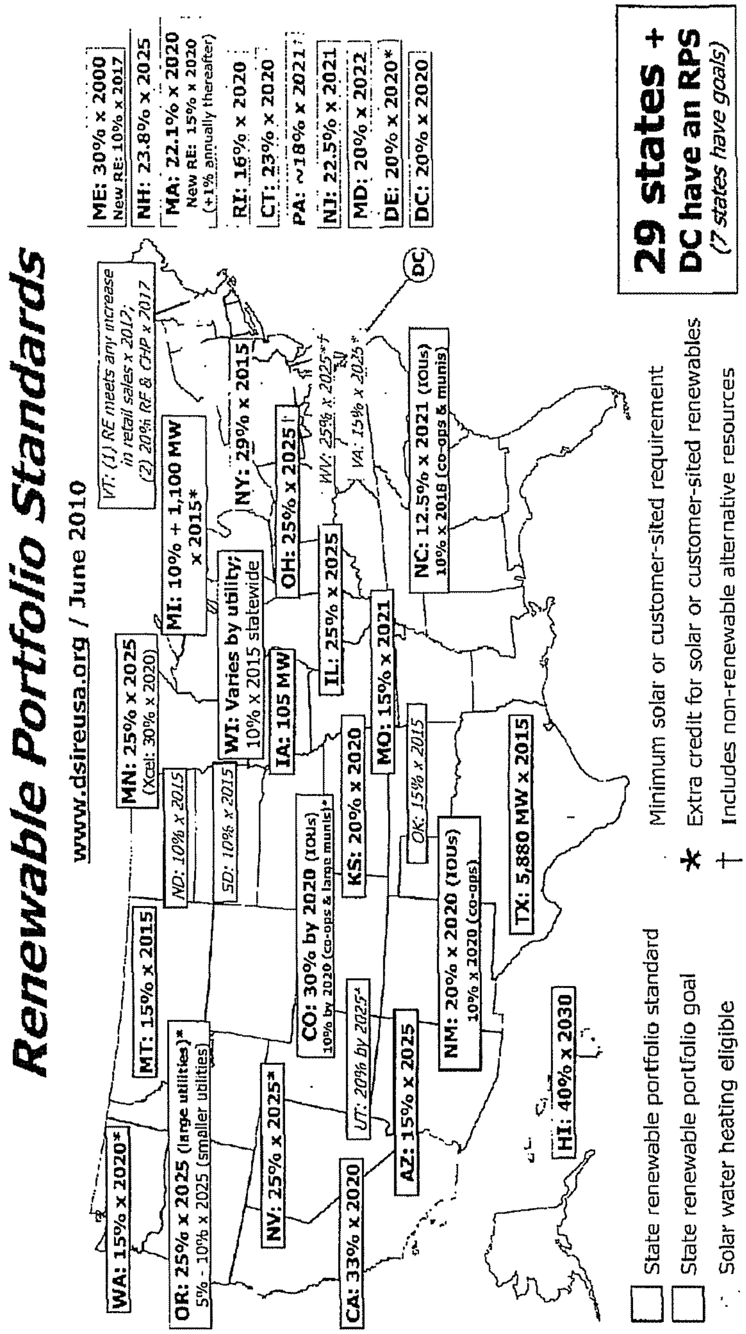
It should be noted that the conclusions of this updated unit disposition study are for the expressed purpose of performing this overall long-term IRP analysis and reflect on-going and evolving disposition assessments. ***From a capacity perspective, no formal decisions have been made with respect to specific timing of any such unit retirements,*** *except as identified in the NSR Consent Decree stipulations*. These disposition analyses and renderings are deemed necessary so that the *prospects* for any ultimate decisions can be integrated into a capacity replacement plan in a way that is ratable and practical.

2.3 Renewable Portfolio Standards

As identified in **Exhibit 2-1**, 29 states and the District of Columbia have set standards specifying that electric utilities generate a certain amount of electricity from renewable sources. Seven other states have established renewable energy goals. Most of these requirements take the form of "renewable portfolio standards," or RPS, which require a certain percentage of a utility energy sales to ultimate customers come from renewable generation sources by a given date. The standards range from modest to ambitious, and definitions of renewable energy vary. Though climate change may not always be the primary motivation behind some of these standards, the use of renewable energy does deliver significant GHG reductions. For instance, Texas is expected to avoid 3.3 million tons of CO_2 emissions annually with its RPS, which requires 2,000 MW of new renewable generation by 2009.

At the federal level, an RPS ranging from 10-20% was proposed for inclusion in the *Energy Independence and Security Act of 2007*; but the final bill as passed into law did not contain an RPS. However, a combined federal renewable energy standard (RES) and energy efficiency standard (EES) of 20% by 2020 was adopted as part of the Waxman-Markey bill passed by the House. The Senate passed out of Committee a combined 15% RES/EES by 2021 and is also considering the House legislation. However, on July 27, 2010 Senate Majority Leader Harry Reid introduced a modest package of draft energy legislation which did not include a renewable standard. Therefore, there is only a slight possibility of passage of a federal RPS in 2010, with much improved likelihood in 2011.

Exhibit 2-1: Renewable Standards by State



2.3.1 Implication of Renewable Portfolio Standards on the AEP-East IRP

Renewable Portfolio Standards and goals have been enacted in well over half of the states in the U.S and over two-thirds of the PJM states. Adoption of further RPS at the state level or the enactment of Federal carbon limitations and/or an RPS will impose the need for adding more renewables resulting in a significant increase in investments across the renewable resource industry.

Wind is currently one of the most viable large-scale renewable technologies and has been added to utility portfolios mainly via long-term power purchase agreements (PPA). Recently, many IOUs have begun to add wind projects to their generation portfolios. The best sites in terms of wind resource and transmission are rapidly being secured by developers. Further, while an extension of the Federal Production Tax Credit (PTC) and investment tax credits (ITC) for wind projects - to the end of 2012 - was enacted in February 2009, it may not be extended further as the implementation of federal carbon or renewable standards is expected to make unnecessary the development incentive provided by the PTC/ITC. Acquiring this renewable energy and/or the associated Renewable Energy Credit/Certificate (REC) sooner limits the risk of increased cost that comes with waiting for further legislative clarity nationally or in the AEP states, combined with the likely expiration of these federal incentives. AEP has experienced, however, that regulators in states without mandatory standards are reluctant to approve PPAs that result in increased costs to their ratepayers. By the end of 2010 AEP operating companies I&M, APCo, and AEP-Ohio (CSP & OPCo) will be receiving energy from at least 9 wind contracts and 1 solar project, with total nameplate ratings of 636 MW. **Exhibit 2-2** summarizes the AEP-East Zone's renewable plan, by operating company.

Exhibit 2-2: Renewable Energy Plan Through 2030

AEP System - East Zone
Potential Renewables Profile to Achieve a System-Wide 10% Target by 2020, and 15% by 2030 [(a)]
as well as Known or Emerging State Mandates
2010 IRP

Year	APCo Solar Nameplate (MW)	APCo Wind Nameplate (MW)	APCo Biomass Equivalent (MW)	APCo Energy as % of Sales	I&M Solar Nameplate (MW)	I&M Wind Nameplate (MW)	I&M Biomass Equivalent (MW)	I&M Energy as % of Sales
2009	0	75	0	0.8%	0	0	0	0.0%
2010	0	276	0	2.7%	0	150	0	2.5%
2011	0	376	0	3.8%	0	150	0	2.6%
2012	0	376	0	3.6%	0	150	0	2.4%
2013 (b)	0	376	0	3.5%	0	200	0	3.2%
2014	0	376	0	3.5%	0	350	0	5.6%
2015	0	376	0	3.5%	0	650	0	10.2%
2016	0	376	0	3.5%	0	650	0	10.3%
2017	0	376	0	3.5%	0	650	0	10.3%
2018	0	376	0	3.4%	0	650	0	10.3%
2019	0	376	0	3.4%	0	650	0	10.4%
2020	0	376	0	3.4%	0	650	0	10.3%
2021	0	378	0	3.3%	0	700	0	11.0%
2022	0	409	0	3.8%	0	700	0	11.0%
2023	0	409	0	3.6%	0	700	0	10.9%
2024	0	409	0	3.5%	0	750	50	13.7%
2025	0	409	0	3.6%	0	800	50	14.3%
2026	0	409	0	3.5%	0	850	50	15.0%
2027	0	409	0	3.4%	0	850	50	14.9%
2028	0	409	0	3.4%	0	850	50	14.8%
2029	0	409	0	3.4%	0	850	50	14.7%
2030	0	409	0	3.3%	0	850	50	14.7%

Year	KPCo Solar Nameplate (MW)	KPCo Wind Nameplate (MW)	KPCo Biomass Equivalent (MW)	KPCo Energy as % of Sales	AEP-Ohio Solar Nameplate (MW)	AEP-Ohio Wind Nameplate (MW)	AEP-Ohio Biomass Equivalent (MW)	AEP-Ohio Energy as % of Sales	AEP-East Solar Nameplate (MW)	AEP-East Wind Nameplate (MW)	AEP-East Biomass Equivalent (MW)	AEP-East Energy as % of Sales
2009	0	0	0	0.0%	0	0	0	0.0%	0	75	0	0.2%
2010	0	0	0	0.0%	0	100	0	0.7%	0	526	0	1.6%
2011	0	0	0	0.0%	20	100	44	1.1%	20	626	44	2.1%
2012	0	0	0	0.0%	31	200	44	1.8%	31	726	44	2.3%
2013 (b)	0	0	0	0.0%	41	250	44	2.1%	41	826	44	2.6%
2014	0	100	0	4.2%	67	300	94	3.3%	67	1,126	94	3.8%
2015	0	100	0	4.2%	94	400	94	4.0%	94	1,526	94	5.0%
2016	0	100	0	4.2%	120	650	50	5.3%	120	1,776	50	5.6%
2017	0	100	0	4.2%	146	800	50	6.3%	146	1,926	50	6.0%
2018	0	100	0	4.2%	172	850	150	8.4%	172	1,976	150	6.9%
2019	0	100	0	4.1%	198	850	150	9.1%	198	2,076	150	7.2%
2020	0	100	0	4.1%	225	1,100	150	10.2%	225	2,226	150	7.6%
2021	0	150	0	6.1%	256	1,100	200	11.2%	256	2,326	200	8.3%
2022	0	150	0	6.0%	301	1,167	200	11.8%	301	2,426	200	8.6%
2023	0	150	0	6.0%	301	1,367	200	13.1%	301	2,626	200	9.1%
2024	0	150	50	11.1%	345	1,467	200	13.8%	345	2,776	300	10.2%
2025	0	150	50	11.1%	345	1,567	200	14.4%	346	2,826	300	10.5%
2026	0	150	50	11.0%	384	1,667	200	15.0%	384	3,076	300	10.9%
2027	0	200	63	14.1%	364	1,767	238	16.2%	384	3,226	350	11.6%
2028	0	200	63	14.0%	389	1,867	238	16.8%	389	3,326	350	11.8%
2029	0	200	63	13.9%	389	1,887	238	16.7%	389	3,328	350	11.7%
2030	0	200	63	13.8%	420	1,867	238	16.7%	420	3,326	350	11.7%

(a) Data excludes conventional (run-of-river) hydro energy as a renewable source as it has been excluded from certain state and proposed federal RPS criteria.
(b) 2012/2013 represent the initial years for Federal RPS/RES mandates as currently proposed by several draft bills before Congress. Further, 2013 would represent the initial year after the likely expiration of Production Tax Credits (PTC) for, particularly, wind resources. Establishment of a federal renewables standard would likely eliminate further extension of such PTC opportunities.

Source: AEP Resource Planning

2.3.2 Ohio Renewable Portfolio Standards

Ohio Substitute SB 221 Alternative Energy requires that 25% of the retail energy sold in Ohio come from "Alternative Energy" sources by 2025. Alternative Energy consists of two main constituents, Advanced Energy and Renewable Energy. Advanced Energy includes distributed generation, clean-coal technology, advanced nuclear technology, advanced solid-waste conversion, plant efficiency improvements and demand-side management/energy efficiency above the levels mandated in the energy efficiency and Renewable Energy provisions. Renewable Energy includes solar (photovoltaic or thermal), wind, incremental hydro, geothermal, solid-waste decomposition, biomass, biologically-derived methane, fuel cells, and storage resources.

At least one-half of the Alternative Energy mandate must be met with renewable resources by 2025. Advanced Energy must provide the balance of the 25 percent goal not attained with Renewable Energy. There is a further sub-requirement that solar constitute at least 0.5 percent of retail sales by that date, and that at least half the renewable resources be from sites located in the State of Ohio. Compliance may be satisfied with the purchase of Renewable Energy Certificates (REC). There are annual benchmark requirements, which began in 2009, for the Renewable and Solar requirement and sub-requirement, respectively. **Exhibit 2-3** shows the results of the current plan for AEP-Ohio in meeting the renewable energy requirements.

Exhibit 2-3: Ohio Renewable Energy Requirement and Plan

AEP-Ohio Renewables Requirement and Plan

Full Year	Solar Benchmark		Solar Plan	Total Benchmark		Total Plan
	Pct	GWh	GWh	Pct	GWh	GWh
2010	0.010%	4	0	0.50%	223	303
2011	0.030%	13	26	1.00%	440	498
2012	0.060%	26	37	1.50%	657	796
2013	0.090%	40	48	2.00%	896	951
2014	0.120%	54	76	2.50%	1,130	1,512
2015	0.150%	68	104	3.50%	1,592	1,827
2016	0.180%	82	132	4.50%	2,048	2,403
2017	0.220%	100	160	5.50%	2,498	2,862
2018	0.260%	118	188	6.50%	2,945	3,804
2019	0.300%	136	216	7.50%	3,393	4,119
2020	0.340%	154	245	8.50%	3,839	4,578
2021	0.380%	171	278	9.50%	4,274	4,996
2022	0.420%	188	326	10.50%	4,700	5,236
2023	0.460%	205	326	11.50%	5,126	5,810
2024	0.500%	223	374	12.50%	5,563	6,145
2025	0.500%	223	374	12.50%	5,567	6,432

Note: (2008/2010) Benchmarks (were/will be) met with both Purchased and Plan RECs

Source: AEP Resource Planning

2.3.3 Michigan Clean, Renewable, and Efficient Energy Act

Michigan's "Clean, Renewable, and Efficient Energy Act" (2008 PA 295) requires that 10 percent of retail sales be met from renewable resources by the year 2015. The initial requirement is for 2012 and the percentage ramps up over the next three years as shown in **Exhibit 2-4.** New sources must be within Michigan or in the retail service territory of the provider, outside of Michigan. Credit is given for existing sources, such as I&M's hydroelectric plants. Renewable Energy Credits will have a three-year life in Michigan.

Exhibit 2-4: AEP I&M-Michigan Renewable Requirement and Plan

I&M Michigan Renewables Requirement and Plan

Full Year	Renewable Benchmark		Total Renewable Energy Plan	Existing Hydro Credits	Total Plan
	Pct	GWh	GWh	GWh	GWh
2010	0.0%	0	0	0	0
2011	0.0%	0	0	0	0
2012	2.0%	59	70	17	88
2013	3.3%	99	93	17	110
2014	5.0%	148	161	17	178
2015	10.0%	296	293	17	310
2016	10.0%	295	293	17	310
2017	10.0%	295	293	17	310
2018	10.0%	295	293	17	310
2019	10.0%	296	293	17	310
2020	10.0%	298	293	17	310
2021	10.0%	299	315	17	332
2022	10.0%	300	315	17	332
2023	10.0%	302	315	17	332
2024	10.0%	303	397	17	414
2025	10.0%	305	419	17	436

Source: AEP Resource Planning

2.3.4 Virginia Voluntary Renewable Portfolio Standard

Virginia Code section 56-585.2 creates incentives for utilities to meet voluntary renewable energy goals. The basis of the goals is energy sales in 2007 less energy provided by nuclear plants. The goals are 4% of that sales figure in 2010, 7% by 2016, 12% by 2022, and 15% by 2025. Double credit is given for energy from solar or wind projects. Including the projects in the current plan along with existing run-of-river hydroelectric plants, APCo should have sufficient credits required to meet the voluntary goals for each year of the Planning Period even though the Virginia State Corporation Commission denied the Company's request for recovery of Virginia share of costs associated with its three most recent wind purchased power agreements totaling 201 MW (90 MW net).

2.3.5 West Virginia Alternative and Renewable Energy Portfolio Standard

The West Virginia Alternative and Renewable Energy Portfolio Standard act was passed in the 2009 session of the West Virginia Legislature (SB297). Since its initial passage it has been amended three separate times, once apparently by a transcription error. The act requires that as of January 1, 2015 electric utilities (an electric distribution company or electric generation supplier who sells electricity to retail customers in West Virginia) must own "credits" equal to a certain percentage of the electric energy sold to customers in West Virginia in the previous year. For 2015 to 2019 the credits must equal 10 percent of the previous year's sales. For 2020 to 2024, the credits must equal 15 percent and after January 1, 2025 the credits must equal 25 percent. The requirements apparently sunset on June 30, 2026 as the result of a section added from one of the amendments.

Credits can be earned by either the utilization of an "alternative energy resource," a "renewable energy resource" or the employment of an "energy efficiency or demand-side energy initiative project" or a "Greenhouse gas emission reduction or offset project." The act carries specific definitions and sub-characterizations related to each of these categories.

2.4 Energy Efficiency Mandates

The Energy Independence and Security Act of 2007 ("EISA") requires, among other things, a phase-in of lighting efficiency standards, appliance standards, and building codes. The increased standards will have a discernable effect on energy consumption. Additionally, mandated levels of demand reduction and/or energy efficiency attainment, subject to cost effectiveness criteria, are in place in Ohio, Indiana and Michigan in the AEP-East Zone. The Ohio standard, if cost-effective criteria are met, will result in installed energy efficiency measures equal to over 20 percent of all energy otherwise supplied by 2025. Indiana's standard achieves installed energy efficiency reductions of 13.90% by 2020 while Michigan's standard achieves 10.55%. Virginia has a voluntary 10% by 2020 target, while West Virginia allows energy efficiency to count towards its renewable standard. No mandate currently exists in Kentucky, however KPCo has offered DR/EE programs to customers since the mid-1990's.

2.4.1 Implication of Efficiency Mandates: Demand Response/Energy Efficiency (DR/EE)

The AEP System (East and West zones) has internally committed to system-wide peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh, approximately 60-65% of which is in the AEP-East zone. Concurrently, several states served by the AEP System have mandated levels of efficiency and demand reduction. Within the AEP-East zone, Ohio and Michigan have statutory benchmarks which took effect in 2009. As a result of the DSM generic case in Indiana, regulatory benchmarks have been put into effect beginning in 2010 for Indiana. In lieu of mandates or benchmarks, stakeholders expect realistic levels of cost-effective demand-side measures to be employed. While this IRP establishes a method for obtaining an estimate of DR/EE that is reasonable to expect for the zone, as a whole; the ratemaking process in the individual states will ultimately shape the amount and timing of DR/EE investment.

2.4.2 Ohio Energy Efficiency Requirements

Energy Efficiency must produce prescribed reductions in energy usage that cumulatively add to 22.2 percent of annual retail energy sold by the year 2025. Additionally, peak demand must be reduced 7.75 percent by 2018. Annual Energy Efficiency and Demand Response benchmark goals have been in-place since 2009.

2.4.3 Transmission and Distribution Efficiencies

The IRP also takes into account other technology initiatives designed to improve the efficiency of the AEP energy delivery and distribution systems. These initiatives include the demonstration of technologies for more effective integrated volt/var controls (IVVC) and community energy storage on the distribution system (CES) that would reduce customer usage, as well as advanced transmission infrastructure technologies to reduce energy losses within the energy delivery system. The transmission and distribution technology programs are designed to avoid or defer the need for infrastructure and reduce emissions by avoiding energy usage and energy lost in the transmission and distribution of energy to ultimate AEP customers.

2.5 Issues Summary

The increasing number of variables and their uncertainty has added to the complexity of producing an integrated resource plan. No longer are the variables merely the cost to build and operate the generation, a forecast of what had traditionally been stable fuel prices and growth in demand over time. Volatile fuel prices and uncertainty surrounding the economy and environmental legislation require that the process used to determine the traditional "supply and demand" elements of a resource plan is sufficiently flexible to incorporate more subjective criteria. The introduction of a cap-and-trade system around CO_2 and high capital construction costs weigh unfavorably on solid-fuel options, but conclusions must be metered with the knowledge that there is a great deal of uncertainty.

One way of dealing with uncertainty is to maintain optionality. That is, if there exists the potential for very expensive carbon legislation, one might favor a solution that minimizes carbon emissions, even if that solution is not the least expensive. Likewise, while there may not yet be a national RPS, procuring or adding wind generation resources now will put a company ahead of the game if one does come to pass. In this way, the company is trading future uncertainty for a known cost. Lastly, adding diversity to the generating portfolio reduces the risk of the overall portfolio. That may not be the least expensive option in a "base" (or most probable) case, but it minimizes exposure to adverse future events and could reduce the ultimate cost of compliance if the resultant demand for renewable resources continues to grow, outpacing the supplier resource base.

3.0 Current Supply Resources

The initial step in the IRP process is the demonstration of the region-specific capacity resource requirements. This "needs" assessment must consider projections of:

- Existing capacity resources—current levels and anticipated changes
- Changes in capability due to efficiency and/or environmental retrofit projects
- Changes resulting from decisions surrounding unit disposition evaluations
- Regional capacity and transmission constraints/limitations
- Load and (peak) demand (see **Section 4.2**)
- Current DR/EE impacts (see **Section 4.3**)
- RTO-specific capacity reserve margin criteria (see **Section 5.1**)

In addition to the establishment of the absolute annual capacity position, an additional "need" to be discussed in this section will be a determination of the specific operational expectation (duty type) of generating capacity–baseload vs. intermediate vs. peaking.

3.1 Existing AEP Generation Resources

Exhibit 3-1 offers a summary of all supply resources for the AEP-East zone (with detail appearing in **Appendix A**). The current (June 1, 2010) AEP-East summer supply of 27,810 MW is composed of the following resource components (the coal resources include AEP's share of OVEC):

Exhibit 3-1: AEP-East Capacity (Summer) as of June 2010

Supply Resource Type	Nameplate (Winter) Rating MW	% of Total	Summer Rating MW	PJM UCAP MW
Coal	22,385	77%	22,152	22,136
Nuclear	2,115	7%	2,029	2,029
Hydro	745	3%	680	948
Gas/Diesel	3,186	11%	2,865	3,256
Wind	718	2%	80	48
Solar	10	0%	4	0
Total	**29,159**	**100%**	**27,810**	**28,417**

Source: AEP Resource Planning

3.2 Capacity Impacts of Generation Efficiency Projects

As detailed in **Appendix B**, the capability forecast of the existing AEP-East generating fleet reflects several unit up-ratings over the IRP period, largely associated with various turbine efficiency upgrade projects planned by AEP-EP&FS for selected 1,300 and 800 MW-series coal-steam turbine generating units. Additionally, AEP continues to work towards improving heat rates of its generating fleet. Such improvements, while not necessarily increasing capacity, do improve fuel efficiency.

3.2.1 D. C. Cook Nuclear Plant (Cook) Extended Power Uprating (EPU)

A change which is <u>not</u> included in **Appendix B** but which is reflected in the 2010 Plan is a strategic project that will increase the generating capability of Cook Units 1 and 2. Implemented in conjunction with a series of plant modifications tied to NRC relicensing requirements to improve design and operating margins and to address component aging issues, a net capacity increase of more than 400 MWe from the two units appears technically and economically achievable. Three interrelated issues challenge the continued economic performance of Cook:

1. Design and operating margins of some systems, structures, and components (SSCs) are lower than desirable and should be enhanced to support improved operational flexibility and satisfy regulatory expectations.
2. Many SSCs will reach end-of-life prior to expiration of the extended Nuclear Regulatory Commission plant license and need to be replaced to maintain margins and allow continued plant operation.
3. The Nuclear Steam Supply Systems for Cook-1 and Cook-2 were designed and built with substantial conservatism to allow uprating, but with the exception of minor Margin Recovery Uprating of about 1.7% performed on each unit, this conservatism remains largely untapped.

Consequently, the Cook Plant does not produce its maximum potential cost-effective electrical output. License changes and modification of selected systems and components could increase the capacity of both units and effectively decrease ongoing plant production costs. However, if not properly implemented, the analyses and modifications needed for uprating could introduce performance or reliability concerns that would negate the value of the capacity increase. The problem to be addressed by the EPU Project is to integrate necessary margin improvement and on-going life cycle management efforts with an uprating for each Cook unit to the maximum safe and reliable reactor thermal power achievable while demonstrating and achieving cost justification of uprating on a life-cycle basis.

A break even analysis performed using the *Strategist* resource optimization model shows that the EPU Project is economical even at costs significantly exceeding the current preliminary estimates and as such has been "embedded" in this 2010 IRP.

3.3 Capacity Impacts of Environmental Compliance Plan

As also detailed in **Appendix B**, the capability forecast of the existing generating fleet reflects several unit de-ratings associated with environmental retrofits (largely scrubbers or CCS) over the IRP period. The net impact to existing units as a result of the planned up-ratings and de-ratings is reflected in that appendix.

3.4 Existing Unit Disposition

Another important initial process within this IRP cycle was the establishment of a long-term view of disposition alternatives facing older coal-steam units in the east region. The Existing Unit Disposition identified 13 sets of aging AEP-East zone generating assets consisting of a total of 26 units with a summer rating of 5,343 MW.

- Big Sandy Unit 1 (273 MW) KPCo
- Conesville Unit 3 (165 MW) CSP
- Clinch River Units 1-3 (690 MW) APCo
- Glen Lyn Unit 5 (90 MW) APCo
- Glen Lyn Unit 6 (235 MW) APCo
- Kammer Units 1-3 (600 MW) OPCo
- Kanawha River Units 1 & 2 (400 MW) APCo
- Muskingum River Units 1 & 3 (395 MW) OPCo
- Muskingum River Units 2 & 4 (395 MW) OPCo
- Picway Unit 5 (95 MW) CSP
- Sporn Units 1-4 (580 MW) APCo (Units 1 & 3), OPCo (Units 2 & 4)
- Sporn Unit 5 (440 MW) OPCo
- Tanners Creek Units 1-4 (985 MW) I&M

Among this group of units are several that were impacted by the Consent Decree from the settled New Source Review litigation. These units, and the dates by which, according to the agreement, they must be retired, repowered, or retrofitted (R/R/R) with FGD and SCR systems, are:

- ✓ Conesville Unit 3, by **December 31, 2012**
- ✓ Muskingum River Units 1-4, by **December 31, 2015**
- ✓ Sporn Unit 5, by **December 31, 2013**
- ✓ A total of 600 MW from Sporn 1-4, Clinch River 1-3, Tanners Creek 1-3, or Kammer 1-3, by **December 31, 2018**.

In order to develop a comprehensive assessment of potential unit disposition recommendations, a team encompassing multiple functional disciplines (engineering, operations, fuels, environmental, and commercial operations) also sought to confirm or challenge the preliminary economic findings by examining additional factors relevant to the units' unique physical characteristics. A decision matrix was employed to assist in that assessment. Relative scores were constructed for each unit under the established criteria. Such scores were based on the analysis and professional judgment surrounding each unit's known (or anticipated) infrastructure liabilities, operational flexibility capabilities in PJM, as well as work force and socioeconomic impacts.

3.4.1 Findings and Recommendations—AEP-East Units

The Unit Disposition Working Group findings are summarized here and in **Exhibit 3-2**. Given the size (over 5,000 MW) of the group of AEP-East units "fully exposed" to future emission expenses for CO_2, possible new mercury/hazardous air pollutant and coal combustion residuals (CCR) rulemakings, it is practical to begin a stepped approach to their disposition–thus avoiding the need to build and finance multiple replacement facilities simultaneously.

- ✓ Recognize that the retirement date represents the year that the unit is projected to no longer provide firm ***capacity*** value in PJM, **however it still may provide *energy* value** and therefore operate well beyond the planned capacity retirement date.
- ✓ The initial unit retirements include only those R/R/R units designated in the NSR Consent Decree. Through 2014 this includes Sporn 5, 440 MW, retiring in **2010** (R/R/R date 2013); Conesville 3, 165 MW (R/R/R date 2012) and Muskingum River 2 & 4, 395 MW (R/R/R date 2015) retiring in **2012**; and Muskingum River 1 & 3, 395 MW (R/R/R date 2015), with a potential retirement date of **2014**.
- ✓ The remaining "fully exposed" units are projected to retire between 2015 and 2019, assuming a staggered implementation schedule for any HAPs/Mercury/CCR regulations that may be imposed on a unit specific basis.

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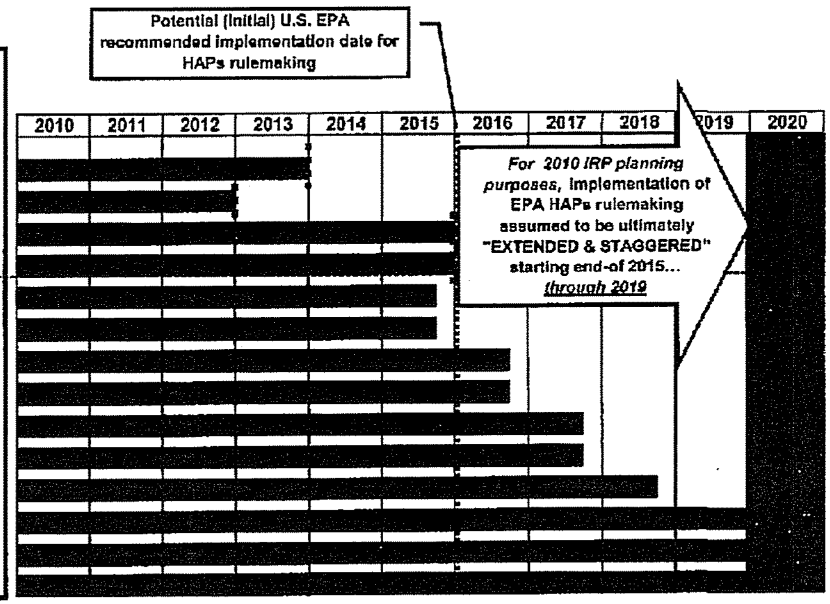
Exhibit 3-2: AEP East Fully Exposed Unit Disposition/Retirement Profile

"FULLY EXPOSED" UNITS (AEP-East)
PROPOSED ***Disposition Plan -- 2010 IRP***

	Oper Co.	Summer Capacity MW	Black Start/Sys Restoration* ALR Capable MW	Black Start/Sys Restoration* Available for Sys. Restart MW	Units Designated "Extended-Start-up"
Sporn 5	OPCo	440			Sporn 5
Conesville 3	CSP	165			-
MR 2&4	OPCo	395			MR 4
MR 1&3	OPCo	395	190	395	-
Glen Lyn 5	APCo	90			Glen Lyn 5
Glen Lyn 6	APCo	235			Glen Lyn 6
Tanners 1-3	I&M	485	340	485	Tanners 1&2
Clinch Rvr 1-3	APCo	690	460	690	Clinch Rvr 3
Picway 5	CSP	95			Picway 5
Sporn 1-4	AP/OP	580	435	580	Sporn 4
Kanawha 1-2	APCo	400	400	400	-
Kammer 1-3	OPCo	600	600	600	**
Big Sandy 1	KPCo	273			-
Tanners 4	I&M	500			-



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capacity Removed From Service	440		560		395	325	1,175	675	400	1,373
Cumulative Capacity Removed	*440*		*1,000*		*1,395*	*1,720*	*2,895*	*3,570*	*3,970*	*5,343*

Capacity (and Energy) Operation | NSR R/R/R Date | Optional Energy (only)

* AEP-East Black Start units include: Smith Mt. U3; Claytor Hydro U2; Big Sandy Peaking (Constellation).
** One of the Kammer units is available for Extended Start-up, however, given that two units are required to be available to support Ormet load, one of the 3 units may be "substituted" to provide that duty

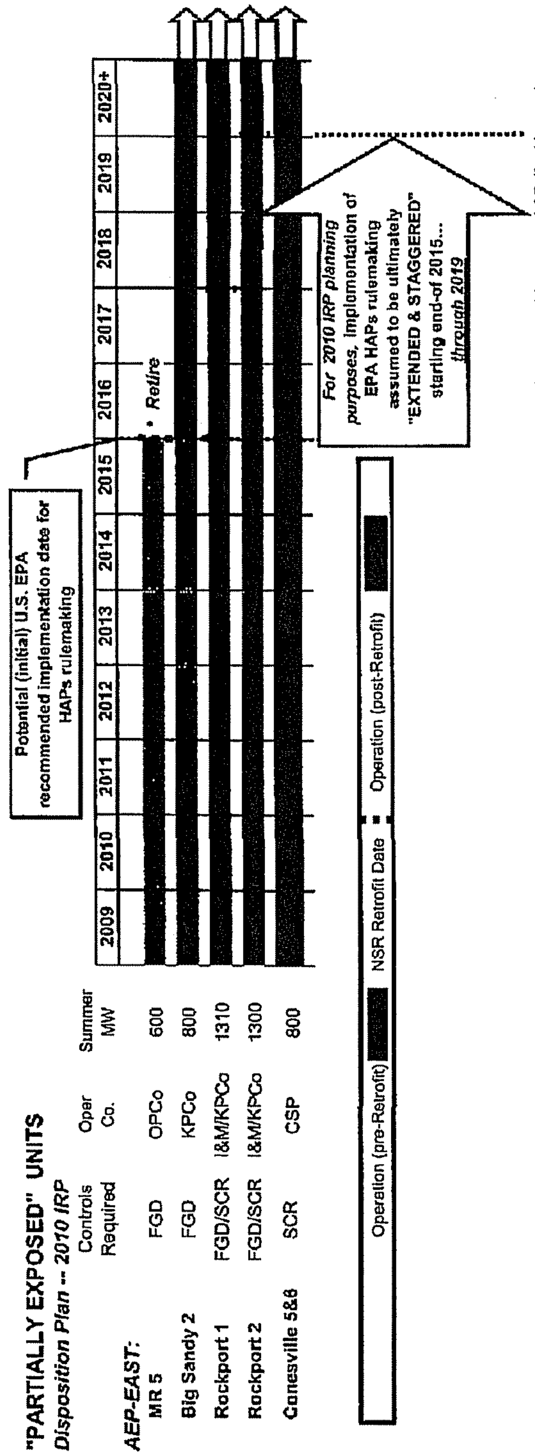
Source: AEP Resource Planning

In addition, certain larger, supercritical coal units which are considered "partially exposed" to these same potential regulations due to their lack of specific environmental control equipment were also evaluated for possible retirement. These units include:

- Big Sandy Unit 2 (800 MW, summer rating) KPCo - requires FGD by 2015
- Muskingum River Unit 5 (600 MW) OPCo – requires FGD by 2015
- Rockport Units 1and 2 (2610 MW) I&M/KPCo – requires FGD/SCR by 2017 (Unit 1)/2019 (Unit 2)
- Conesville Units 5 and 6 (CSP) (790 MW) – requires SCR by 2019

The Resource Planning group analyzed, under two pricing scenarios, various options for each unit including retrofitting, retiring, or converting to gas. With the exception of Muskingum River 5, the decision to retrofit with the required controls represents the lowest cost for AEP-East customers. (See **Exhibit 3-3**) As with all long range planning assumptions, the decision to retrofit or retire these partially exposed units will be revisited in subsequent IRPs. As rules surrounding HAPS, CCR, and the Transport Rule are finalized, more certainty with regard to the timing and magnitude of incremental capital investments to comply with these regulations will certainly factor into the retrofit/retire decision making process. Given FGD construction lead times and the NSR Consent Decree stipulations, a final decision on Muskingum River 5 and Big Sandy 2 will be required before the end of 2011.

Exhibit 3-3: Partially Exposed Unit Disposition Profile



Note: "Partially-Exposed" units represent more recent-vintage, larger, higher-thermal efficiency coal units that are not currently retrofitted with both scrubbers *and* SCR (for Hg, etc.)
* This represents the MR5 stipulated NSR Consent Decree retrofit date. Optionality around MR5 may ultimately be sought that would attempt to operate the unit in some non-controlled fashion *beyond* 12/2015... *up to* any 'Extended & Staggered' HAPs implementation date

Source: AEP Resource Planning

3.4.2 Extended Start-Up

As part of AEP's continuing effort to manage operating and maintenance expenses, AEP-East launched a plan to place 10 generating units - representing 1,925 megawatts (MW) of capacity - in "extended startup" status for nine months of the year. This action includes the 450-MW Unit 5 at the Sporn Plant. AEP had announced plans to mothball Sporn 5 in April of 2009, noting that the unit has no PJM capacity obligations in 2010. Because Sporn 5 has no PJM capacity obligation, it will be the only unit to operate in the four-day "extended startup" mode year-round.

The plan, which took effect June 1, 2010 allows the company to re-deploy and maximize the productivity of employees at several coal-fired units that are projected to run less frequently over the next few years.

The units that will be placed in extended startup status are:

- Picway Unit 5, 95 MW, CSP;
- Muskingum River Unit 4, 215 MW, OPCo;
- Clinch River Unit 3, 235 MW, APCo.;
- Tanners Creek Units 1 & 2, 290 MW, I&M.;
- Glen Lyn Units 5 & 6, 335 MW, APCo;
- Sporn Units 3, 4 & 5, 750 MW, APCO (Unit 3), OPCO (Units 4&5); and

In extended startup mode, the affected units will remain off line until needed to meet demand. When needed, plant staff will be able to start the affected units during a window of four days during the nine non-peak months of the year. In addition, Kammer Units 1-3 (OPCo) are now in a "substitute operation" mode, where only two units will be staffed and operating at any one time.

3.4.3 Implications of Retirements on Black Start Plan

The eventual retirement of Conesville 3, and in time other units such as the Muskingum River and Tanners Creek units, will have implications for the System's plans for black-start capability and Automatic Load Rejection, which are needed to restore the system following a transmission system collapse. In addition, PJM rules for the provision of black-start service and NERC Standards regarding the maintenance of a system restoration plan have implications on the planning, timing, announcement, etc. of the unit retirements. The AEP Generation, Transmission, and Commercial Operations groups have studied this issue and developed a list of recommended system restoration options. As the highest priority option, AEP generation engineering and Conesville plant management are completing control modifications and a test program to provide automatic load rejection capability for Conesville 5 and 6.

3.4.4 Applicable PJM Rules

Black start resources maintain a rolling two-year commitment to PJM. The PJM tariff therefore requires up to two years' advance notice of retirement.

If PJM and the Transmission Owner determine there is a need to replace the deactivating black start resource, PJM will seek replacement of the retiring resource as follows:

1) PJM will post on-line a notification about the need for a new black start resource along with the location and capability requirements.
2) This posting opens a market window which will last 90 calendar days.
3) PJM will review each pending Generation Interconnection request, each new interconnection request in the market window, and each proposal from a black start unit to evaluate whether any project could meet the black start replacement criteria.
4) The Transmission Owner will have the option of negotiating a cost-based, bilateral contract in accordance with the existing process outlined in Schedule 6A of the OATT. The Transmission Owner may provide an alternative as one of the bids that will be evaluated by PJM pending FERC approval.
5) If PJM and the Transmission Owner determine more than one of the proposed projects meets the replacement criteria, the most cost-effective source will be chosen.
6) If no projects are received during the 90-day market window, PJM and the Transmission Owner will revisit the definition of the location and capability requirements, to allow more resources to become viable, even if sub-optimal.

After PJM and the Transmission Owner identify the most cost-effective replacement resource, PJM and the Transmission Owner will coordinate with the Generation Owner for the their acceptance under the PJM tariff as a black start unit.

The black start resource will be compensated for provision of black start service in accordance with the existing process in the PJM tariff.

3.4.5 AEP's Required Actions and Options

If AEP retires Conesville 3 in 2012, PJM must be notified in 2010. PJM will require the Conesville 3 black-start capability to be replaced and the Conesville 5 and 6 control system modifications are expected to provide for automatic load rejection capability for those units. If the Conesville 5 and 6 tests are successfully completed this fall, it is expected that Conesville 5 and 6 will be automatic load reject capable and can replace and/or augment the service previously provided by Conesville 3. Accordingly, AEP Generation is coordinating with AEP Transmission Operations to update the System Emergency Operations Plan to take this capability into account after the control modifications are successfully tested by year-end 2010.

AEP and its customers will pay for the black-start service, either by providing the service or by purchasing it. AEP will continue to improve and enhance its System Emergency Restoration plans to ensure compliance with all applicable NERC Standard protocols.

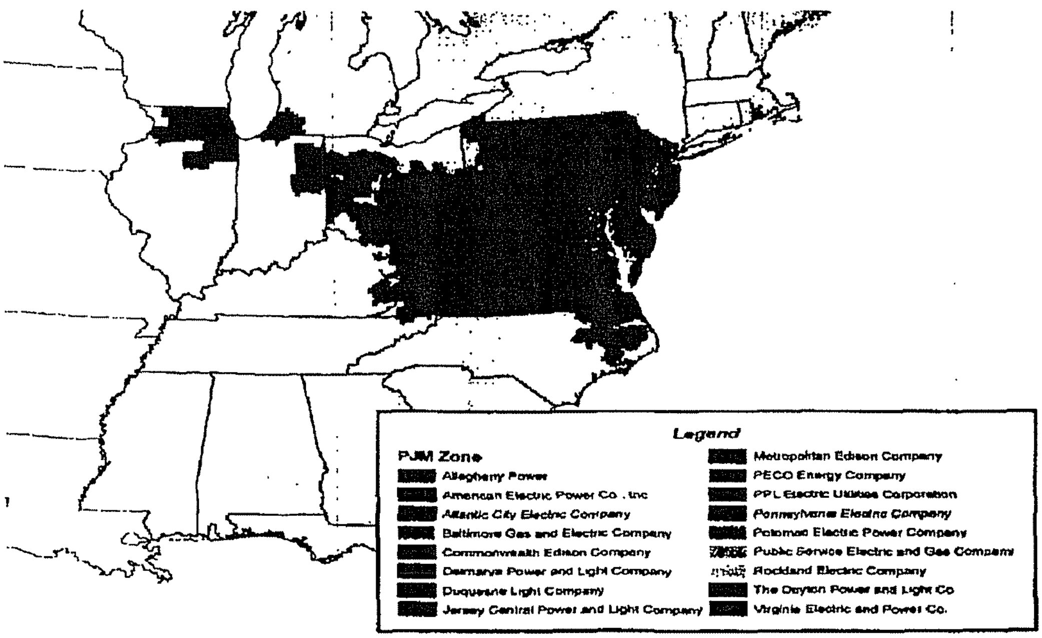
3.5 AEP Eastern Transmission Overview

3.5.1 Transmission System Overview

The eastern Transmission System (eastern zone) consists of the transmission facilities of the seven eastern AEP operating companies. This portion of the Transmission System is composed of approximately 15,000 miles of circuitry operating at or above 100 kV. The eastern zone includes over 2,100 miles of 765 kV overlaying 3,800 miles of 345 kV and over 8,800 miles of 138 kV. This expansive system allows AEP to economically and reliably deliver electric power to approximately 24,200 MW of customer demand connected to the eastern Transmission System that takes transmission service under the PJM open access transmission tariff.

The eastern Transmission System is the most integrated transmission system in the Eastern Interconnection and is directly connected to 18 neighboring transmission systems at 130 interconnection points, of which 49 are at or above 345 kV. These interconnections provide an electric pathway to facilitate access to off-system resources and serve as a delivery mechanism to adjacent companies. The entire eastern Transmission System is located within the Reliability*First* (RFC) Regional Entity. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization, and has been participating in the PJM markets (see **Exhibit 3-4**).

Exhibit 3-4: AEP-PJM Zones and Associated Companies



Source: www.pjm.com

3.5.2 Current System Issues

As a result of the eastern Transmission System's geographical location and expanse as well as its numerous interconnections, the eastern Transmission System can be influenced by both internal and external factors. Facility outages, load changes, or generation redispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the eastern Transmission System is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern Transmission System conforms to the NERC Reliability Standards, the applicable RFC standards and performance criteria, and AEP's planning criteria.

AEP's eastern Transmission System assets are aging and some station equipment is obsolete. Therefore, in order to maintain acceptable levels of reliability, significant investments will have to be made over the next ten years to proactively replace the most critical aging and obsolete equipment and transmission lines.

3.5.3 PJM RTO Recent Bulk Transmission Improvements

Despite the robust nature of the eastern Transmission System, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant transmission enhancement to the eastern AEP Transmission System over the last few years was completed in 2006. This was the construction of a 90-mile 765 kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, EHV/138 kV transformer capacity has been increased at various stations across the eastern Transmission System.

3.5.4 Impacts of Generation Changes:

Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern Transmission System. Currently, there is more than 28,000 MW of AEP generation and over 6,000 MW of additional merchant generation connected to its eastern Transmission System. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for additional generation to be connected to the eastern Transmission System over the next several years. There are also significant amounts of wind generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern Transmission System required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and MISO markets.

The retirement of Conesville units 1 and 2 in 2006 and the potential retirement of Conesville Unit 3 in 2012 will result in the need for power to be transmitted over a longer distance into the Columbus metro area. In addition, these retirements will result in the loss of dynamic voltage regulation. Since there is very little baseload generation in central Ohio, the impact of these retirements could be significant. The retirement of these units requires the addition of dynamic reactive compensation such as a Static VAR Compensator (SVC) device, which will be added within the Columbus metro area in 2012.

Within the eastern Transmission System, there are two areas in particular that could require significant transmission enhancements to allow the reliable integration of large generation facilities:

- **Southern Indiana**—there are limited transmission facilities in southern Indiana relative to the AEP generation resources, and generation resources of others in the area. Significant generation additions to AEP's transmission facilities (or connection to neighbor's facilities) will likely require significant transmission enhancements, including Extra-High Voltage (EHV) line construction, to address thermal and stability constraints. The Joint Venture Pioneer Project would address many of these concerns.
- **Megawatt Valley**—the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations during multiple transmission outages. Multiple overlapping transmission outages will require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Significant generation resource additions in the Gavin/Amos/Mountaineer/Flatlick area will also influence these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers–to more fully integrate the transmission facilities in this generation-rich area. Thermal constraints will also need to be addressed. The Potomac-Appalachian Transmission Highline (PATH) project, which consists of a 765-kilovolt transmission line extending some 276 miles from the Amos Substation in Putnam County, W.Va., to the proposed Kemptown Substation in Frederick County, Maryland, will partially mitigate these constraints.

Furthermore, even in areas where the transmission system is robust, care must be taken in siting large new generating plants in order to avoid local transmission loading problems and excessive fault duty levels.

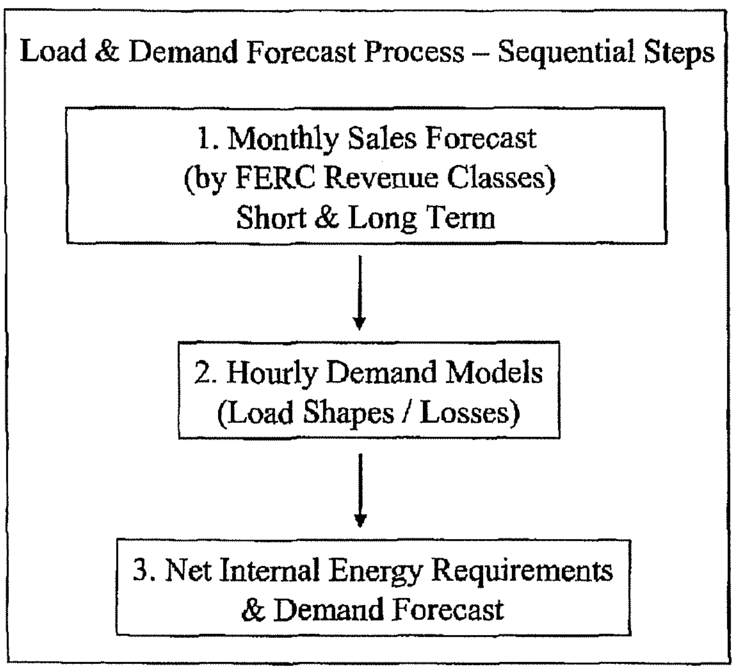
4.0 Demand Projections

4.1 Load and Demand Forecast Process Overview

One of the most critical underpinnings of the IRP process is the projection of anticipated resource "needs," which, in turn, centers on the long-term forecast of load and (peak) demand. The AEP-East internal long-term load and peak demand forecasts were based on the AEP Economic Forecasting group's load forecast completed in April 2010. AEP Economic Forecasting utilizes a collaborative process to develop load forecasts. Customer representatives and other operating company personnel routinely provide input on customers (large customers in particular) and local economic conditions. Taking this input into account, the AEP Economic Forecasting group analyzes data, develops and utilizes economic and load forecast data and models, and computes load forecasts. Economic Forecasting and operating company management team members review and discuss the analytical results. The groups work together to obtain the final forecast results. The forecast incorporates the effects of energy policy on both a state and federal level such as the 2009 American Reinvestment and Recovery Act (ARRA), Energy Independence and Security Act of 2007 (EISA) as well as load/price elasticity associated with policy impacts on the price of electricity.

The electric energy and demand forecast process involves three specific forecast model processes, as identified in **Exhibit 4-1**.

Exhibit 4-1: Load and Demand Forecast Process—Sequential Steps



Source: AEP Economic Forecasting

The first process models the consumption of electricity at the aggregated customer level: Residential, Commercial, Industrial, Other Ultimate customers, and Municipals and Cooperatives. It involves modeling both the short- and long-term sales. The second process contains models that derive hourly load estimates from blended short- and long-term sales, estimates of energy losses for distribution and transmission, and class and end-use load shapes. The aggregate revenue class sales and energy losses is generally called "net internal energy requirements." The third process reconciles historical net internal energy requirements and seasonal peak demands through a load factor analysis which results in the load forecast.

The long-term forecasts are developed using a combination of econometric models to project load for the Industrial, Other Ultimate and Municipal and Cooperative customer classes, as well as, under proprietary license by Itron Inc., Statistically-Adjusted End-use (SAE) models for the modeling of Residential and Commercial classes.

The long-term process starts with an economic forecast provided, under proprietary license, by Moody's Economy.com for the United States as a whole, each state, and regions within each state. These forecasts include projections of employment, population, and other demographic and financial variables for both the U.S. as a whole and for specific AEP service territories. The long-term forecasting process incorporates these economic projections and other inputs to produce a forecast of kilowatt-hour (kWh) sales. Other inputs include regional and national economic and demographic conditions, energy prices, appliance saturations, weather data, and customer-specific information.

The AEP Economic Forecasting department uses Statistically Adjusted End-use (SAE) models for forecasting long-term Residential and Commercial kWh energy sales. SAE models are econometric models with end-use features included to specifically account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005 (EPAct 2005), the Energy Independence and Security Act of 2007 (EISA), and the 2009 American Reinvestment and Recovery Act (ARRA),. SAE models start with the construction of structured end-use variables that embody end-use trends, including equipment saturation levels and efficiency. Factors are also included to account for changes in energy prices, household size, home size, income, and weather conditions. Regression models are used to estimate the relationship between observed customer usage and the structured end-use variables. The result is a model that has implicit end-use structure, but is econometric in its model-fitting technique. The SAE approach explicitly accounts for energy efficiency which has served to slightly lower the forecast of Residential and Commercial class demand and energy in the forecast horizon particularly reflecting the manifestation of energy policy impacts.

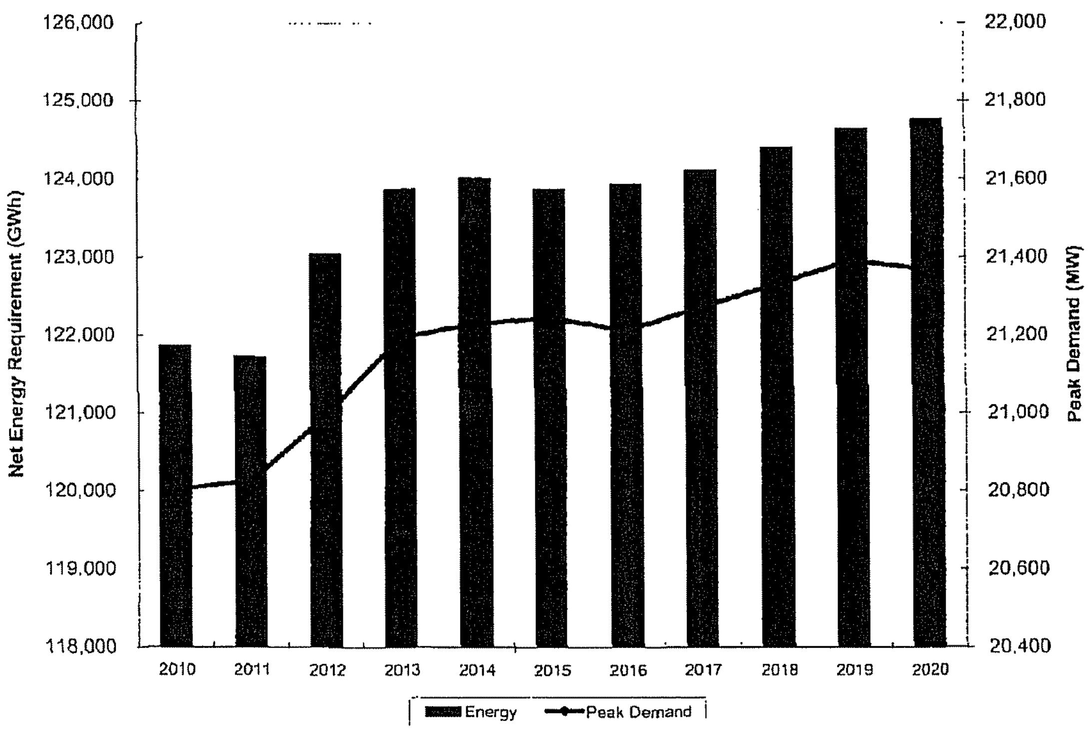
AEP uses processes that take advantage of the relative strengths of both the short and long term methods. The regression models typically used in the shorter-term modeling employ the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. While these models generally produce accurate forecasts in the short run, without specific ties to economic factors they are less capable of capturing the structural trends in electricity consumption that are important for longer-term planning. The long-term modeling process, with its explicit ties to economic and demographic factors, is appropriate for longer-term decisions and the establishment of the most likely, or base case, load and demand over the forecast period. By overlaying these respective method outputs, AEP Economic Forecasting effectively applies the strengths of both load-modeling approaches.

4.2 Peak Demand Forecasts

Exhibit 4-2 reflects the AEP Economic Forecasting Group's forecast of annual peak demand for the AEP-East zone, utilized in this IRP.

Specifically, **Exhibit 4-2** identifies the AEP-East region's internal demand profile as having 0.27% Compound Annual Growth Rate (CAGR) including the impacts of projected (embedded) Demand Response/DSM which will be discussed later in this document. This equates to a **56 MW per year increase** over the 10-year IRP period through 2020 if the load growth was steady. As the graph shows, the impact of the existing recession depresses peak demand in 2010 and 2011 with a gradual increase in 2012 and 2013 from the assumed economic recovery. In addition, the chart indicates a 0.24% rate of growth, reflective of forecasted DSM/energy efficiency impacts, for internal energy sales over the 10-year period.

Exhibit 4-2: AEP-East Peak Demand and Energy Projection

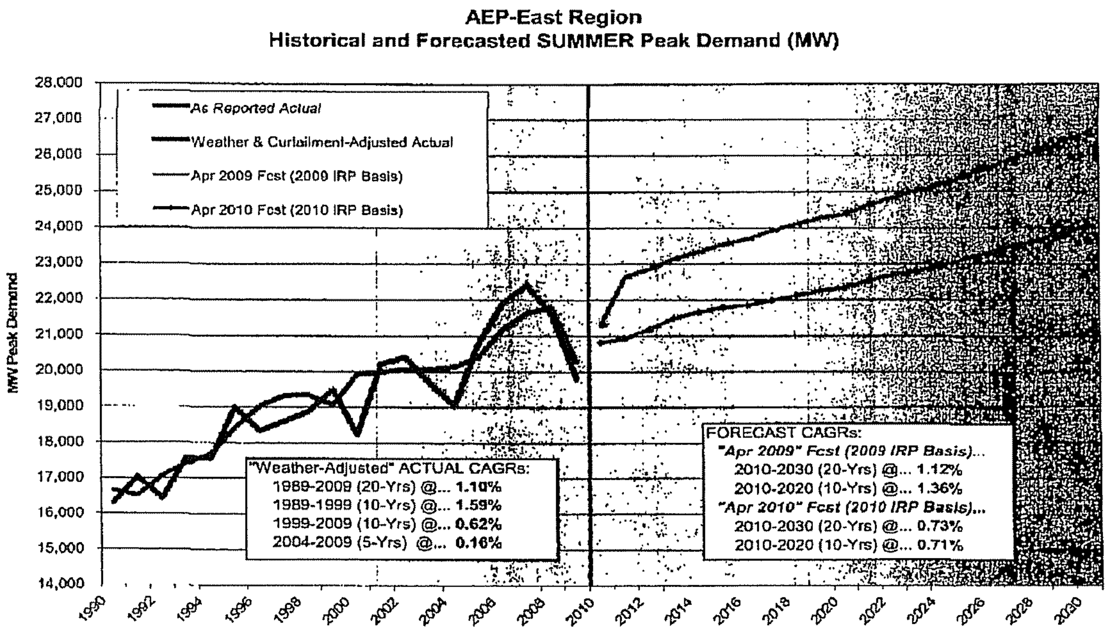


Source: AEP Economic Forecasting

Exhibits 4-3 and **4-4** show the current demand and energy forecasts, respectively, compared to historical actual data and recent forecasts. Note that for both demand and energy, the current forecast is significantly lower as recessionary impacts on demand are being reflected. The impact of future DSM programs has been excluded from the two peak forecasts to make them comparable.

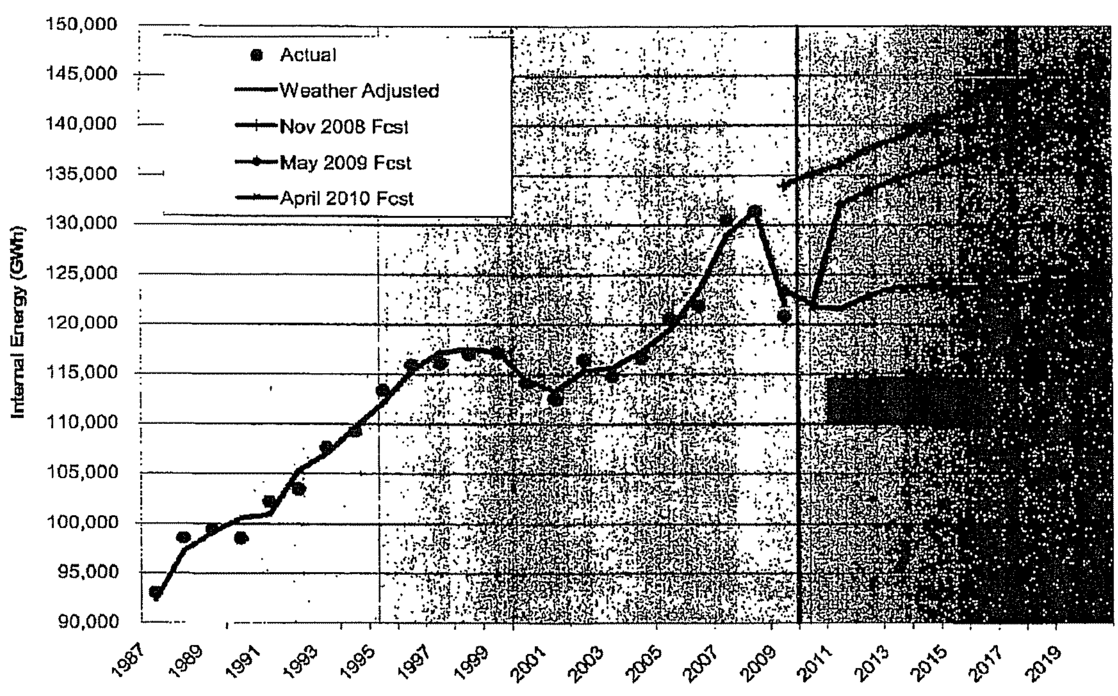
AMERICAN ELECTRIC POWER

Exhibit 4-3: AEP-East Peak Actual and Forecast (Excludes DSM)



Source: AEP Economic Forecasting

Exhibit 4-4: AEP-East Internal Energy Actual and Forecast



Source: AEP Economic Forecasting

4.2.1 Load Forecast Drivers

It is critical to note some of the major assumptions driving these demand profiles for the eastern (AEP-PJM) zone:

1) As set forth earlier in this report, it has been assumed for purposes of this IRP cycle that AEP's Ohio operating company legal entities, OPCo and CSP, *will continue to plan to serve those retail load obligations* for which they have had an historical obligation to serve, beyond the current end of the period set forth under the approved AEP-Ohio Electric Security Plan (ESP) that expires at the end of 2011.
2) The assumption that the load to serve a major industrial load operating six aluminum potlines at its facilities– would *continue at the current existing level of approximately 60% of its full capacity* (approximately 4 potlines). Two other large industrial customers are assumed to remain idle in the forecast.
3) Any major *wholesale load* obligations (largely, municipalities and cooperatives who currently have or have had a relationship with AEP as a "FERC tariff" customer) assumed to be renewed or extended over the planning period under *long-term contracts*. **However**, an observation from the underlying data to support **Exhibit 4-2** is that such firm or "committed" wholesale demand projections are relatively constant over the LT forecast period and, in total, represent a small percentage (< 10%) of the east region's overall load obligation.
4) Additionally, as described below, this forecast incorporates the effects of all current DR/EE program offerings and targets mandated by state commissions. The DR/EE legislative and regulatory mandated goals in Indiana, Michigan and Ohio are very aggressive, yet assumed achievable in the load forecast. It also includes energy efficiency and peak demand reduction that "occurs naturally" as a function of shifting consumer behavior. Consumer-driven, naturally-occurring DR/EE has a significant impact on energy consumption.
5) Finally this forecast incorporates the net effects of *Price Elasticity* (described below). **In** so doing the forecast attempts to predict the load reduction that occurs as a result of a shift in consumer behavior as a reaction to price fluctuations.

The impacts from energy policy such as EISA and ARRA are expected to be reflected on the demand side. These will predominately come through increased lighting, appliance, and building efficiency standards and codes. The efficiency of lighting is set to increase by 20-30% by 2012-24. Efficiency standards for appliance equipment including residential boilers, clothes washers and dishwashers are also set to increase through 2014. Efforts to promote energy efficiency in commercial buildings as well as in industrial energy use are expected as well. **Section 7** of this document details the impacts from the DSM programs that are currently offered as well as program impacts estimated in future years

The economic impacts of a carbon dioxide cap regime will be wide reaching and impact electricity demand through market adjustments in various sectors. As an early attempt to quantify some type of initial impact, a price elasticity effect on demand has been embedded in the load forecast. The timing and impact of this scenario is truly speculative, and represents only one of many possible policy actions.

As mentioned above, one of the drivers of the load forecast deals with price elasticity. An example of a completely inelastic good is one that consumers cannot or will not change their consumption of in response to changes in the price of the product. In the short term, most consumers can make minimal changes to their electricity consumption behavior, so electricity is one example of a fairly inelastic good. The **exception** is energy intensive industrial sectors, where companies can shift production to other facilities, close facilities, switch fuels or change capital equipment. Changing large energy using equipment (A/C, furnace, etc) for most consumers is a long-term decision. To make a truly informed decision, any price differential between the competing fuels must be known to be sustainable for consumers to take the financial risk. The long-term nature of these decisions makes electricity (or natural gas) even less price elastic in the long-term. Since consumers have limited options for change, price changes are very significant and become even more so during stressful economic periods.

Over the last 4 to 6 years, the price of electricity has increased significantly. In real terms (adjusting for inflation), the price increases reverse a long-term trend of prices declining over previous decades. In response, the growth in electricity consumption has been dampened with the increased prices. In an industry with sales growth around 1% per year, even a product with a low price response (elasticity) will see an impact. For example, using 1% load growth with no price changes and an overall own-price elasticity of -0.15, a long-term doubling of price, 100% increase, will result in a 15% decrease in consumption. Over a 15 year period, 1% load growth would be reduced to no load growth. Therefore, the expected costs of achieving environmental, renewable and energy efficiency goals for the company will continue to increase the burden on the consumer and thus reduced load growth going forward.

5.0 Capacity Needs Assessment

Based on the assessment of AEP-East's current resources as described in **Section 3**, and its energy and peak demand projections as discussed in **Section 4**, a capacity needs assessment can be established that will determine the amount, timing and type of resources required for this 2010 IRP Cycle.

- The 2010 AEP-East load forecast as updated in April, 2010, accounts for:
  1) AEP-East region's internal demand profile as having 0.27% CAGR (or 0.71 when projected, embedded DSM is excluded). This equates to **56 MW per year increase** (or 152 MW when DSM is excluded) over the 10-year IRP period through 2020 if the load growth was steady.
  2) A major industrial customer will operate at 60% load;
  3) 1,119 MW of peak demand reduction due to interruptible loads and Advanced Time of Day pricing by 2020.
- The forecast of AEP-East capability additions/subtractions reflected through the ten years 2011 through 2020:
  1) the potential retirement of **2,300 MW** of coal fired capacity by 2015 and up to 6,000 MW by 2020;
  2) 199 MW of plant derates associated with environmental and biomass retrofits partially offset by plant efficiency and other improvements of 73 MW.

5.1 PJM Planning Constructs - Reliability Pricing Model (RPM)

Effective with its 2007/08 delivery year (June 1, 2007 through May 31, 2008), PJM instituted the RPM capacity-planning regime. Its purpose is to develop a long-term price signal for capacity resources as well as load-serving entity (LSE) obligations that is intended to encourage the construction of new generating capacity in the region. The heart of the RPM is a series of capacity auctions, extending out four planning years, into which all generation that will serve load in PJM will be offered. The required reserve margin under RPM is determined by the intersection of the capacity-offer curve with an administratively-drawn demand curve. In steady-state mode, the auction will be held 38 months before the beginning of the plan year, with subsequent incremental auctions to trim up the capacity commitments as capacity commitments, unit reliability/contribution and demand forecasts change.

FERC has authorized, and PJM has provided for an alternative to the capacity auction, called the Fixed Resource Requirement (FRR), which may be appropriate for vertically integrated utilities to use. Under the FRR, the reserve margin is not dependent upon the intersection of the offer curve and the administratively-set demand curve but is built directly upon the fixed PJM Installed Reserve Margin (IRM) requirement as it was prior to the introduction of RPM. This alternative allows opting entities to meet their requirements with a lower capacity requirement than might have resulted under the auction model and with more cost certainty. AEP has previously elected to "opt-out" of the RPM (auction) and has been utilizing the FRR (self-planning) construct. That opt-out of the PJM capacity auction currently is effective through the 2013/14 delivery year, for which the auction was held in

May, 2010. AEP will determine for each subsequent year whether to continue to utilize FRR for an additional year or to "opt-in" to the RPM auction for a minimum five-year commitment period.

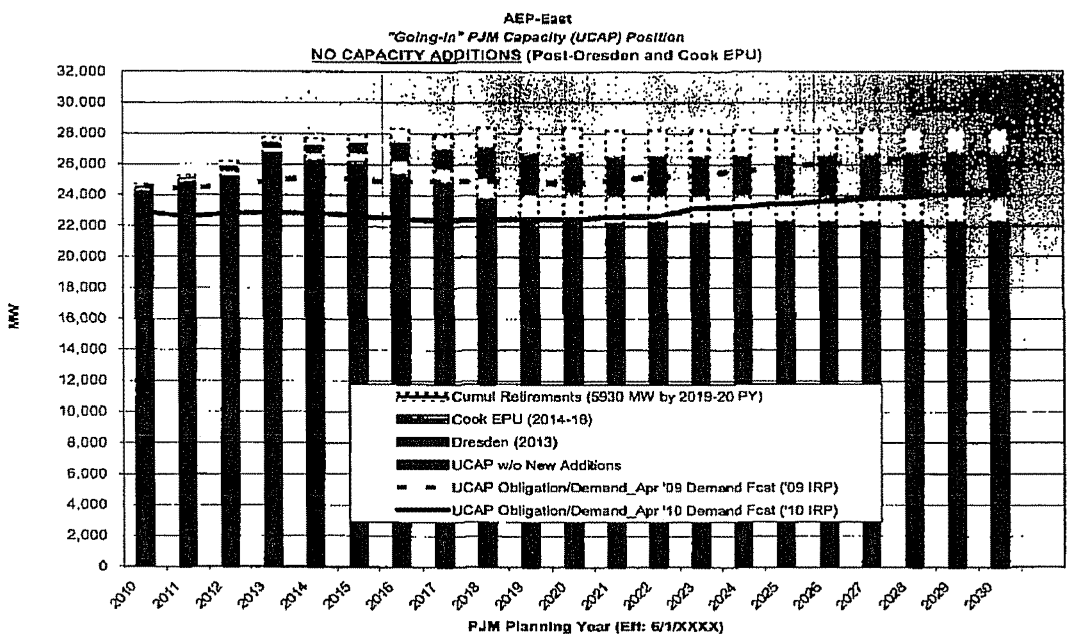
5.2 PJM Going In Forecast and Resources

The demand and resource figures include impacts of existing and approved state/jurisdictional DR/EE programs and existing PPAs for renewable resources. They also include the addition of the 540 MW Dresden combined cycle facility currently under construction. They do not consider new DR/EE programs that were evaluated as part of this year's IRP process or additional renewable resources needed to meet the System's stated goals. The resultant capacity gap arises in the 2018 timeframe and grows in future years, primarily with projected unit retirements.

The forecast considers PJM minimum reserve requirements under PJM's self-planning Fixed Resource Requirements (FRR) capacity alternative and estimated Equivalent Demand Forced Outage Rates (EFORd) of AEP generators.

Exhibit 5-1 offers the "going-in" capacity need of the AEP-East zone prior to uncommitted capacity additions. It amplifies that the region's overall capacity need does not occur until the end of the Planning Period (2018-2019). "Committed" new capacity includes completion of the 540 MW Dresden combined cycle facility in 2013, the assumed performance of the Donald C. Cook Nuclear Plant Extended Power Uprate (EPU) project, and assumed execution of purchase power agreements for renewable energy (largely, wind) resources.

Exhibit 5-1: Summary of Capacity vs. PJM Minimum Required Reserves



Source: AEP Resource Planning

The going-in capacity forecast considered the potential retirement of close to *6,000 MW* of largely older, less-efficient coal-fired units over the Planning Period due largely to external factors including known or anticipated environmental initiative from the U.S. Environmental Protection Agency (EPA), as well as the December 2007 stipulated New Source Review (NSR) Consent Decree. In spite of this potential, this AEP-East IRP requires no new baseload capacity resources in the forecast period. Rather, the proposed EPU initiative at the Cook Station during the 2014-2018 time period and peaking resources required in 2017 and 2018, in addition to wind purchases and DSM are proposed to be added to maintain anticipated minimum PJM nominal (capacity) reserve margin requirements (approximately 15.5% increasing to 16.2%) as well as system reliability/restoration needs. Additional natural gas-fired peaking and intermediate capacity would be added after 2020 to meet future load obligations.

5.3 Ancillary Services

In addition to energy products, PJM provides markets for ancillary services that can be sold by AEP-East generating units in support of the generating and transmission system operated by PJM. Such real-time ancillary markets include (1) regulation, (2) synchronized or spinning reserve, and (3) black start.

Regulation is a form of load-following that corrects for short-term changes in electricity use that might affect the stability of the power system. Synchronized reserve supplies electricity if the grid has an unexpected need for more power on short notice. Black start service supplies electricity for system restoration in the unlikely event that the entire grid would lose power.

Prior to the formation of RTOs, these services were provided in a routine manner by the generating units; there were no markets for them, but the costs were recovered through regulated rates. Potential revenue streams from these services have not been taken directly into account in the IRP in terms of unique resource offerings, but AEP is beginning to account for them in some special applications, such as the evaluation of battery (storage) technology.

5.4 RTO Requirements and Future Considerations

In developing the plans for the AEP-East zone, it was assumed that several factors would remain constant. As indicated, AEP is committed to the FRR alternative to the RPM of PJM through the 2012/2013 delivery year, and *it was assumed that this commitment would continue indefinitely.* Although PJM could contemplate further changes in the IRM, it was also assumed that the PJM IRM would be 15.3%, as currently set for the 2013/14 planning year and remain unchanged for the remainder of the Planning Period. Finally, it was assumed that the underlying PJM EFORd for 2013/14 (6.30%) would remain unchanged for the remainder of the Planning Period.

On the other hand, it was assumed that the AEP unit EFORd would change through time. Existing unit EFORds were projected to change as unit improvements are made or as units near retirement. Also, the addition of new units and removal of old units from the system changes the weighted average EFORd. With the exception delivery year 2010/11, which was heavily impacted by the Cook outage, AEP's EFORd is projected to improve from 8.41% in 2009/10 to 5.02% in 2020/11.

This assumption tends to reduce the amount of new installed capacity needed to meet PJM requirements.

The inclusion of First Energy (FE) and Duke/Cinergy in the PJM footprint will impact the PJM IRM determination for the forecast period. The PJM study entitled 2009 PJM Reserve Requirement Study for the 11-Year Planning Horizon June 1st 2009 - May 31st 2020 dated November 4, 2009 by the PJM Staff included sensitivity study to evaluate the effect of the ATSI move to the PJM footprint. The study did not, however, evaluate the effect of Duke/Cinergy move to PJM Interconnection as this was announced after the completion of the study. The 2010 study should consider the Duke/Cinergy move from Midwest ISO to PJM Interconnection.

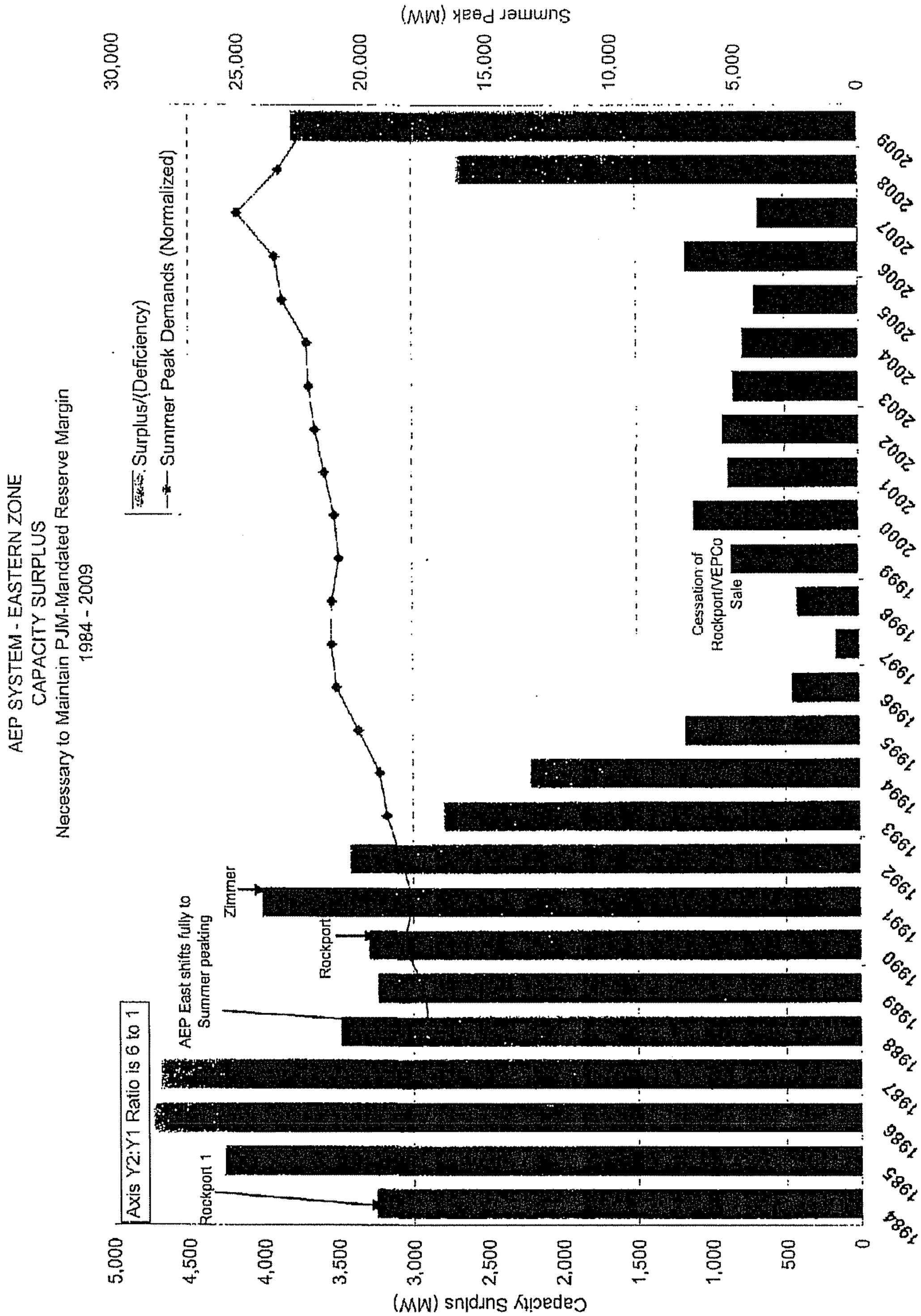
Second, the future valuation of AEP exposed generating assets take into consideration the costs profiles relative to the wholesale market position. The integrated dispatch of FE and Allegheny and the move of Duke/Cinergy generating assets to PJM will impact the PJM wholesale power markets and thus, in turn, the valuation of the AEP exposed generating assets

Beyond the FE and Duke/Cinergy matters, a FERC regulatory matter of note the November, 2009 FERC Declaratory Order issued in response to a petition from SunEdison related to solar energy installations and "retail" energy sales behind the utility meter. This order illustrates the direction of federal policy and how new entrants and new technologies are evolving with respect to retail electricity sales and the intersection of State jurisdictional net metering and FERC jurisdictional wholesale regulations.

5.5 Capacity Positions—Historical Perspective

To provide a perspective, an historical relative capacity position for the AEP-PJM zone is presented in **Exhibit 5-2**. AEP's East zone (as part of ECAR) experienced ample capacity reserves throughout the decade of the 1980s and most of the 1990s. In the early 2000s the trending clearly suggested that anticipated load growth would soon result in zonal capacity deficiencies, on a planning basis. The economic decline that occurred over the past two years has again allowed AEP's East zone to maintain an adequate capacity position however, given the volatility that has been experienced over the past decade, it would be prudent to maintain a flexible plan that can react to quick changes.

Exhibit 5-2: AEP Eastern Zone, Historical Capacity Position



Source: AEP Resource Planning

6.0 Resource Options

6.1 Resource Considerations

An objective of a resource planning effort is to recommend an optimum system expansion plan, not only from a least-cost perspective, but also from the perspectives of planning flexibility, creation of an optimum asset mix, adaptability to risk, conformance with applicable NERC Standards and, ultimately, from the perspective of affordability. In addition, given the unique impact of generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the environmental compliance planning process.

6.1.1 Market Purchases

AEP's planning position for its East Zone is to take advantage of market opportunities when they *are* available and economic, either in the form of limited-term bilateral capacity purchases from non-affiliated sources or by way of available, discounted, merchant generation asset purchases. Such market opportunities could be utilized to hedge capacity planning exposures should they emerge and create (energy) option value to the company.

As with the need to maintain resource planning and implementation flexibility for various supply or demand exposures as identified above, the Plan should likewise seek to continually consider such market "buy" prospects, since:

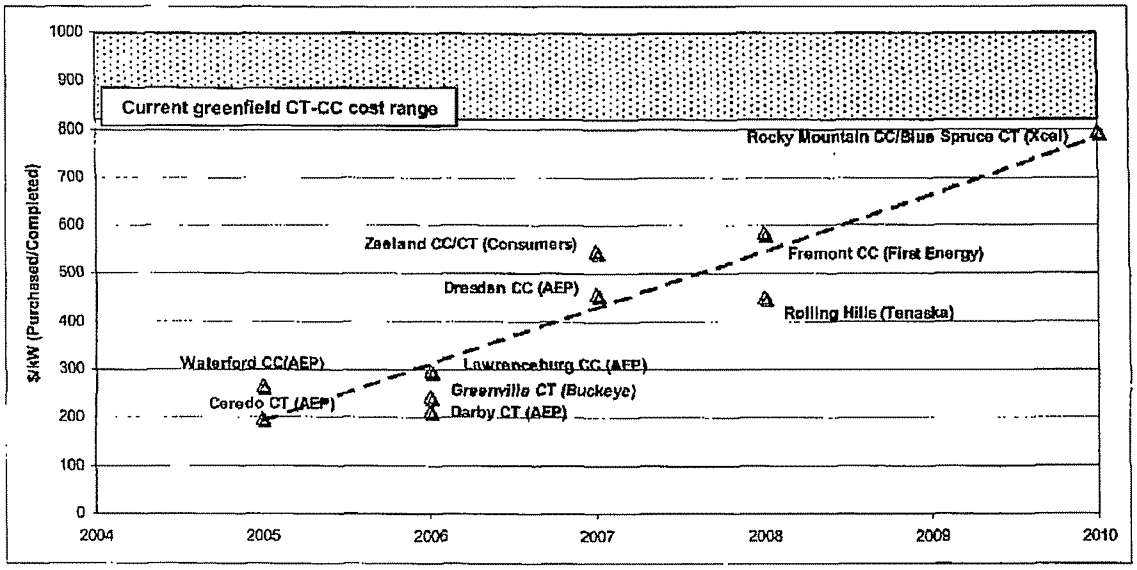
- this IRP assumes the need to ultimately build generating capability to meet the requirements of its customers for which it has assumed an obligation to serve (including Ohio);
- the regional market price of capacity ultimately will, as represented above, begin to approach the fixed cost of new-build generation; and
- the purchase of merchant generation assets relative to new-build generation represents a different risk profile with respect to siting, costs and schedule.

Another critical element ultimately impacting the availability of (bilateral) market capacity purchases is the PJM RPM construct. As discussed, AEP has opted out of the RPM capacity auction. With that, however, comes the fact that the capacity supply available to AEP would be limited to other "FRR" entities within PJM (which are limited), or to capacity resources residing outside of the PJM RTO. However, AEP has an option to participate in RPM so long as AEP remains an RPM participant for no less than 5 years.

6.1.2 Generation Acquisition Opportunities

Other market purchase opportunities are constantly being explored in continued recognition of the need for additional capacity. AEP investigates the viability of placing indicative offers on additional utility or IPP-owned natural gas peaking and combined cycle facilities as such opportunities arise. Analyses are performed in the *Strategist* resource optimization model based on the most recent IRP studies, to estimate a break-even purchase price that could be paid for the early acquisition of such an asset, in lieu of an ultimate green field installation. However, as shown in **Exhibit 6-1**, the cost of these available assets are now beginning to approach that of a greenfield project.

Exhibit 6-1: Recent Merchant Generation Purchases



Source: AEP Resource Planning

6.2 Traditional Capacity-Build Options

6.2.1 Generation Technology Assessment and Overview

AEP's New Generation organization is responsible for the tracking and monitoring of estimated cost and performance parameters for a wide array of generation technologies. Utilizing access to industry collaboratives such as EPRI and Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers as well as its own experience and market intelligence, this group continually monitors supply-side trends. **Appendix C** offers a summary of the most recent technology performance parameter data developed.

6.2.2 Baseload Alternatives

Coal-based baseload technologies include pulverized coal (PC) combustion designs, integrated gasification combined cycle (IGCC), and circulating fluidized bed combustion (CFB) facilities. Nuclear is a viable option, and the application process for the construction of nuclear power plants has been initiated by several utilities. It is the current view of AEP that, while great difficulty and risk still exist in the siting and construction of nuclear power plants, nuclear power should be among the baseload options for the future. Nuclear power was modeled in some scenarios and sensitivities, but ultimately was not included in the final resource plan being recommended due to the uncertainties surrounding costs, schedules, and regulatory recovery.

6.2.2.1 Pulverized Coal

PC plants are the workhorse of the U.S. electric power generation industry. In a PC plant, the coal is ground into fine particles that are blown into a furnace where combustion takes place. The heat from the combustion of coal is used to generate steam to supply a steam turbine that drives a generator to produce electricity. Major by-products of combustion include SO_2, NO_X, CO_2, and ash, as well as various forms of elements in the coal ash including mercury (Hg). The ash byproduct is often used in concrete, paint, and plastic applications.

Steam cycle thermodynamics for the pulverized coal-fired units–which determines the efficiency of generating electricity– falls into one of two categories, *subcritical* or *supercritical.* Subcritical operating conditions are generally accepted to be at up to 2,400 psig/1,000°F superheated steam, with a single or double reheat systems to 1,000°F, while supercritical steam cycles typically operate at up to 3,600 psig, with 1,000-1,050°F main steam and reheat steam temperatures. AEP has recognized the benefits of the supercritical design for many years. All eighteen of the units in the AEP East system built since 1964 have utilized the supercritical design.

There have been advances in the supercritical design over the years, and units are now being designed to operate at or above 3,600 psig and >1,100°F steam temperatures, known as an *ultra supercritical* (USC) design. AEP's Turk plant which is currently under construction in Arkansas is a new USC design.

The initial capital costs of subcritical units are lower than those of a comparable supercritical unit by about 4 to 6%, but the overall efficiency of the supercritical design is higher than the subcritical design by approximately 3%. Due to cycle design improvements, the new variable pressure ultra supercritical units are projected to have an initial capital cost of about 4% greater than a comparable supercritical unit. While the overall efficiency remains approximately 3% better than the comparable supercritical unit, the efficiency improvement is present throughout the entire load range, not just at full load conditions.

This cost-performance tradeoff favors USC designs as fuel and carbon prices increase.

6.2.2.2 Integrated Gasification Combined Cycle

Given the long time-horizons of most resource planning exercises, IRP processes must be able to consider new technologies such as IGCC. The assessment of such technologies is based on cost and performance estimates from commonly cited public sources, consortia where AEP is actively engaged, and vendor relationships, as well as AEP's own experience and expertise.

IGCC is of particular interest to AEP in light of the abundance, accessibility, and affordability of high rank coals for the company–particularly in its eastern zone. IGCC technology with carbon capture has the potential to achieve the environmental benefits closer to those of a natural gas-fired plant, and thermal performance closer to that of a combined cycle, yet with the low fuel cost associated with coal. As discussed in this IRP report, the coal gasification process appears well-positioned for integration of ultimate carbon capture and storage technologies, which will be a critical measure in any future mitigation of greenhouse gas emissions associated with the generation of electricity. The IGCC process employs a gasifier in which coal is partially combusted with oxygen and steam to form what is commonly called "syngas"–a combination of carbon monoxide, methane, and hydrogen. The syngas produced by the gasifier then is cleaned to remove the particulate and sulfur compounds. Sulfur is converted to hydrogen sulfide and ash is converted into glassy slag. Mercury is removed in a bed of activated carbon. The syngas then is fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG), where it produces steam that drives a steam turbine as would a natural gas-fired combined cycle unit.

IGCC enjoys thermal efficiencies comparable to USC-PC. Its ability to utilize a wide variety of coals and other fuels positions it extremely well to address the challenges of maintaining an adequate baseload capability with efficient, low-emitting, low-variable cost generating technology. Further, IGCC is in a unique position to be pre-positioned for carbon capture as, unlike PC technologies, it has the ability to perform such capture on a "pre-combustion" basis. It is believed that this will ultimately lead to improved net thermal efficiency than would be required by PC technology utilizing post-combustion carbon capture technology.

6.2.2.3 Circulating Fluidized Bed Combustion

A CFB plant is similar to a PC plant except that the coal is crushed rather than pulverized, and the coal is combusted in a reaction chamber rather than the furnace of a PC boiler. A CFB boiler is capable of burning bituminous and sub-bituminous coal plus a wide range of fuels that cannot be accommodated by PC designs. These fuels include, coal waste, lignite, petroleum coke, a variety of waste fuels, and biomass. Units are sometimes designed to fire using several fuels, which emphasizes this technology's major advantage fuel flexibility. Coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air blown in from below through a series of nozzles. CFB boilers operate at lower temperatures than pulverized coal-fired boilers. The energy conversion efficiency of CFB plants tends to be slightly lower than that of pulverized coal-fired counterparts of the same size and steam conditions because of higher excess air and auxiliary power requirements.

CFB boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_X formation, and capture SO_2 in situ. Specifically, SO_2 is captured during the combustion process by limestone being fed into the bed of hot particles that are fluidized by the combustion air blown in from below. The limestone is converted into free lime, which reacts with the SO_2. Currently, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. A 500 MW unit is in initial stage of operations in Poland. AEP has no commercial operating experience with generation utilizing circulating fluidized bed boilers but is familiar with the technology through prior research, including the Tidd pressurized fluidized bed demonstration project. Commercial CFB units utilize a subcritical steam cycle, resulting in a lower thermal efficiency.

6.2.2.4 Carbon Capture

CO_2 capture is the separation of CO_2 from a flue gas stream or from the atmosphere and the recovery of a concentrated stream of CO_2 that is suitable for storage or conversion. Efforts are focused on systems for capturing CO_2 from coal-fired power plants, although the technologies developed will need to also be applicable to natural-gas-fired power plants, industrial CO_2 sources, and other applications. In PC plants, which are 99% of all coal-fired power plants in the United States, CO_2 is exhausted in the flue gas at atmospheric pressure at a concentration of 10-15% volume. This is a challenging application for CO_2 capture because:

- The low pressure and low CO_2 concentration dictate a high volume of gas to be treated.
- Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 absorption processes.
- CO_2 capture processes require large amounts of steam and electricity to separate the CO_2 from the flue gas stream thereby increasing unit heat rates, increasing auxiliary power requirements and reducing the electrical energy available for delivery to ultimate customers.
- Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1,200 to 2,000 pounds per square inch) adds to the large parasitic load.

Aqueous amines are the current state-of-the-art technology for CO_2 capture for PC power plants. The 2020 Department of Energy aspirational goal for advanced CO_2 capture systems is that CO_2 capture and compression added to a newly constructed power plant increases the cost of electricity no more than 35%, versus the current 65%, relative to a no-capture case.

However, with IGCC technology, CO_2 can be captured from a synthesis gas (coming out of the coal gasification reactor) before it is mixed with air in a combustion turbine. The pre-combusted CO_2 is relatively concentrated (50% of volume) and at higher pressure. These conditions offer the opportunity for lower-cost CO_2 capture. The 2012 Department of Energy aspirational goal for advanced CO_2 capture and storage systems applied to an IGCC is no more than a 10% increase in the cost of electricity from the current 30%. It is a more stringent goal even though the conditions for CO_2 capture are more favorable in an IGCC plant.

6.2.2.4.1 Carbon Capture Technology and Alternatives

Reducing CO_2 emissions from a fossil-fuel technology can be accomplished in three ways: increased generating efficiency thereby lowering the emission rate or CO_2 produced per unit of electric energy produced, removing the CO_2 from the flue gas, or reducing the carbon content of the fuel. While effective, increasing the generating efficiency of a coal-based plant has its practical limitations from a design and performance perspective. Removing the CO_2 from the flue gas of a PC plant is a very expensive process. Currently, the only demonstrated technology used to "scrub" the CO_2 from the flue gas is by using an amine-based absorption process.

As previously mentioned in this report, AEP is pursuing an alternative approach. AEP is currently conducting a validation of Alstom's chilled ammonia PC carbon capture technology on a 20

MW flue gas slipstream at its 1,300 MW Mountaineer Plant in West Virginia. It is anticipated that this technology, when fully developed, will achieve 90% CO_2 capture with a 15% parasitic loss and netting a lower cost than other retrofit technologies. Based on the results of the Mountaineer slip-stream test, a subsequent 235 MW commercial installation of this chilled ammonia technology is in the early stage of Phase I development for Mountaineer.

This 235 MW cost/performance profile will be modeled in subsequent IRPs.

6.2.2.5 Carbon Storage

Storage is the placement of CO_2 into a repository in such a way that it will remain stored for hundreds of thousands of years.

Geologic formations considered for CO_2 storage are layers of porous rock deep underground that are "capped" by a layer of nonporous rock above them. The storage process consists of drilling a well into the porous rock and then injecting pressurized ("spongy" liquid) CO_2 into it. The CO_2 is buoyant and flows upward until it encounters the layer of nonporous rock and becomes trapped. There are other mechanisms for CO_2 trapping as well. CO_2 molecules dissolve in brine and react with minerals to form solid carbonates, or are absorbed by porous rock. The degree to which a specific underground formation is suitable for CO_2 storage can be difficult to discern. Research is aimed at developing the ability to characterize a formation before CO_2 injection to be able to predict its CO_2 storage capacity. Another area of research is the development of CO_2 injection techniques that achieve broad dispersion of CO_2 throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock. These two areas, site characterization and injection techniques, are interrelated because improved formation characterization will help determine the best injection procedure.

6.2.2.6 Nuclear

Although new reactor designs and ongoing improvements in safety systems make nuclear power an increasingly viable option as a new-build alternative due to it being an emission-free power source, concerns about public acceptance/permitting, spent nuclear fuel storage, lead-time, capital costs and completion risk continue to temper its consideration. For these stated reasons, among others, AEP does not view new new nuclear capability as a viable candidate to meet the capacity resource needs of AEP-East within this near-term period (2010-2020). However, portfolios that include nuclear capacity beyond the near-term period and into the expected second wave of new builds are comparable with the hybrid portfolio that was ultimately selected. Both the economic and political viability of nuclear power and energy will continue to be explored given:

1) the AEP-East zone's ultimate need for baseload capacity;
2) the cost and performance uncertainty surrounding the advancement and commercialization of IGCC technology;
3) the cost and performance uncertainty of carbon capture and storage technology; and

4) the continued push to address AEP's carbon footprint and the mitigating impact additional nuclear power clearly would have in that regard.

Growth in U.S. nuclear generation since 1977 has been primarily achieved through "uprating" – the practice of increasing capacity at an existing nuclear power plant. As of October 2009, the NRC had approved 129 uprates totaling 5,726 MWe of capacity. That amount is equivalent to adding another five-to-six conventional-sized nuclear reactors to the electricity supply portfolio. Extended power uprates (EPU) can provide up to 20% of additional capacity. The EPU and related projects for the Cook Plant (as described in **Section 3.2.1** of this report) – are therefore consistent with the recent trends in the nuclear industry.

6.2.3 Intermediate Alternatives

Intermediate generating sources are typically expected to serve a load-following and cycling duty and shield baseload units from that obligation. Historically, many generators, such as AEP's eastern fleet, have relied on older, less-efficient, subcritical coal-fired units to serve such load-following roles. Over the last several years, these units' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and sub-critical units are retired, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

6.2.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a heat recovery steam generator (HRSG) producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-55% LHV), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years NGCC plants were often selected to meet new intermediate and certain baseload needs. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

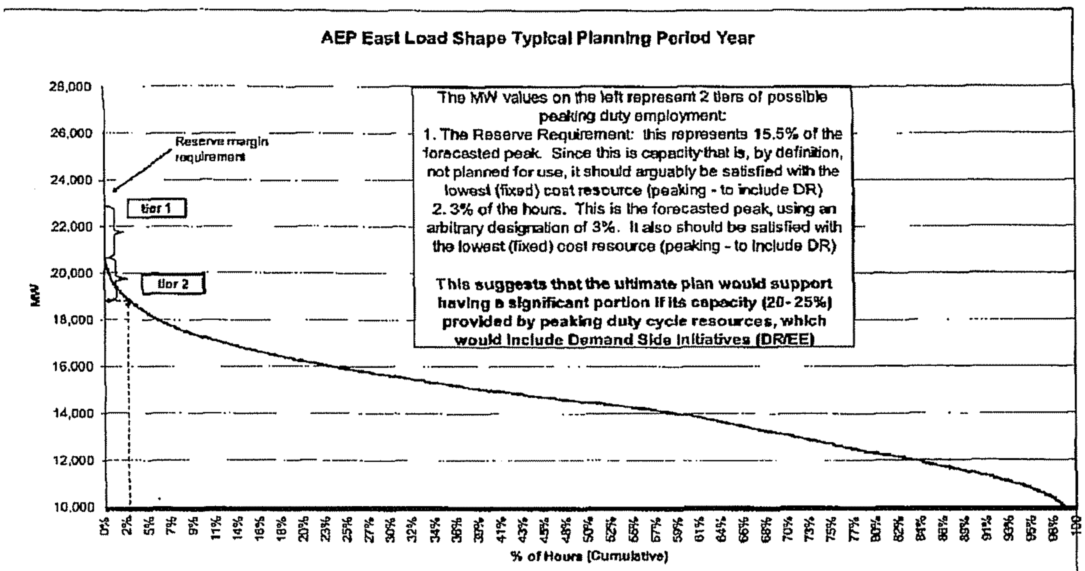
- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

6.2.4 Peaking Alternatives

Peaking generating sources are required to provide needed capacity during extreme high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide very little energy over an annual load cycle. As a result, fuel efficiency and other variable costs are of less concern. This capacity should be obtained at the lowest practical installed cost, despite the fact that such capacity often has very high energy costs. For this reason, acquisition of existing gas generation assets at below market prices is the preferred choice for meeting peaking requirements. This peaking requirement is manifested in the system load duration curve, an example of which is shown in **Exhibit 6-2**. This curve shows the hourly demand for each hour in a typical year. Note that there is a notable drop off in demand after the highest 3% of the hourly loads. This drop off supports the position that the lowest installed cost investment, or lowest life cycle cost investment when considering the minimal capacity factors these peaking facilities will experience, are selected by optimization modeling.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency (Black Start) capability to the grid.

Exhibit 6-2: AEP East Typical Load Duration Curve



Source: AEP Resource Planning

6.2.4.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" combustion turbine systems, air compressed by an axial compressor (front section) is mixed with fuel and burned in a combustion chamber (middle section). The resulting hot gas then expands and cools while passing through a turbine (rear section). The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A simple cycle combustion turbine system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, i.e., not recovered as in a combined cycle design. While not as efficient (at 30-35% LHV), they are, however, inexpensive to purchase, compact, and simple to operate. Further, simple cycle frame CTs can be started up and placed in service far more rapidly (30 minutes) than a combined cycle unit requiring four or more hours from start to full load resulting from the CC unit thermal steam cycle.

6.2.4.2 Aeroderivatives (AD)

Aeroderivatives are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7EA frame machine requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is on the order of 20% higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown, make the aeroderivatives well suited to peaking generation needs. The aeroderivatives can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide aeroderivatives the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: a) the penetration of variable renewables increase, b) baseload generation processes become more complex limiting their ability to load follow and; c) intermediate coal-fueled generating units are retired from commercial service.

Aeroderivatives weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an aeroderivative over an industrial turbine. Aeroderivatives in the less than 100 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in the aeroderivative units.

Some of the better known aeroderivative vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[5]

[5] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG

6.2.5 Energy Storage

Energy storage refers to technologies that allow for storage of energy during off-peak periods of demand and discharge of energy during periods of peak demand. This has the effect of flattening the load curve by reducing the peaks and "filling the valleys." In this sense, it is considered a peaking asset. Energy storage can also be applied at other times to temporarily mitigate transmission congestion if it is economically to do so in conjunction with generating resources that are curtailed by inadequate transmission infrastructure. Energy storage consists of batteries (Sodium Sulfur "NaS," Lithium Ion, and others), super capacitors, flywheels, compressed air energy storage (CAES) or pumped hydro storage. Pumped storage hydro uses two water reservoirs, separated vertically. During off peak hours water is pumped from the lower reservoir to the upper reservoir. When required, the water flow is reversed to generate electricity.

The investment requirements for pumped hydro storage are significant. Further, site-selection and attainment of FERC licensing represent huge challenges. NaS Batteries are the leading technology under consideration for prospective storage-related utility planning with several variations of compressed air energy storage in research and development.

6.2.5.1 Sodium Sulfur Batteries (NaS):

Storage technologies are receiving greater consideration due partly to the improved battery-storage technologies; efficiencies now are approaching 90%. That, coupled with the ability to offer market time-of-day pricing arbitrage by charging during low-cost off-peak periods and discharging at higher-cost daytime periods, works to its advantage. Battery installations can be located near load points, thus avoiding transmission and distribution line losses associated with traditional generation. The downside currently is the significant manufactured cost per kW, transportation limitations due to their weight, and total installed costs in the range of $2,000 per kW.

In light of battery-storage's potential for: 1) market arbitrage, 2) line loss reduction, 3) deferral of selected distribution infrastructure through selective siting of storage capacity, coupled with the prospect for reduced capital costs due to improvements in battery technology, its consideration as a potential capacity resource is warranted.

6.2.5.2 Community Energy Storage (CES)

Community energy storage (CES) is being tested as a distributed storage option. The use of distributed storage technology, which will involve the placement of small energy storage batteries throughout residential areas, will look similar to the small transformer boxes currently seen throughout neighborhoods. Each box should be able to power four to six houses. AEP is testing this potential distribution game-changing technology, which should also provide voltage sag mitigation as well as emergency transformer load relief.

6.3 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). Numerous renewable energy sources such as solar, geothermal, new hydro, and tidal are either under development or exist. However not all are economic options for AEP within the service territory based on their current state of development, or for financial, meteorological, or geographical reasons. Within the AEP service territory, without significant leaps in technology, biomass co-firing in coal power plants and wind power plants are the primary options for economically (or realistically) generating electricity on a significant scale from renewable sources.

As highlighted in the **Section 2** Introduction, although effective in 29 states (9 of 13 PJM states) plus the District of Columbia, a mandatory RPS exists today in Ohio, West Virginia and Michigan, and a voluntary RPS exists in Virginia. The prospect of a Federal RPS and additional state standards is sufficiently tenable to warrant an evaluation of renewable generation in conjunction with this IRP process. Further, renewable energy sources deliver attractive CO_2 benefits in a potentially carbon-constrained policy environment, should that environment be realized.

AEP's New Technology Development group continues to evaluate a wide range of renewable technologies, with the latest updates (December 2009) included in **Appendix I.** Technologies were evaluated on cost, location, feasibility, applicability to AEP's service territory, and commercial availability. After a high-level evaluation, economic screening was carried out considering each technology's estimated costs and effectiveness, to develop a levelized $/MWh cost. Costs and benefits considered in the screening included project capital and O&M costs; avoided capacity and energy costs; alternative fuel costs; alternative emission rates and associated allowance costs; and available federal or state production tax credits, if any. The levelized cost was used to rank the various technologies and also was compared to AEP-East's avoided cost to calculate an imputed REC value. A project is considered reasonable if the projected market value of equivalent RECs is greater than this imputed REC value for a particular technology.

The renewable technologies ultimately screened include:

- biomass co-firing on existing coal-fired units
- separate injection of biomass on existing coal-fired units
- wind farms
  - ✓ evaluated separately for the East and West regions
  - ✓ with or without the federal production tax credit & investment tax credit
- solar generation
  - ✓ with or without the federal investment tax credit
- incremental hydroelectric production
- landfill gas with microturbine
- geothermal generation
- distributed generation.

Although some of the renewable technologies listed above could be economic, AEP is constrained from doing some of these projects because the energy sources are not practical in AEP service territory (e.g., geothermal). Similarly, biomass co-firing is constrained by a supply of suitable fuel and/or transportation options anticipated to be in proximity to the host coal units evaluated. *Thus, the renewable resources available to be included in the Plan are not necessarily the least expensive options screened, but rather those that provide suitable economics and practicality to achieve emerging state or federal mandates.*

6.3.1 Wind

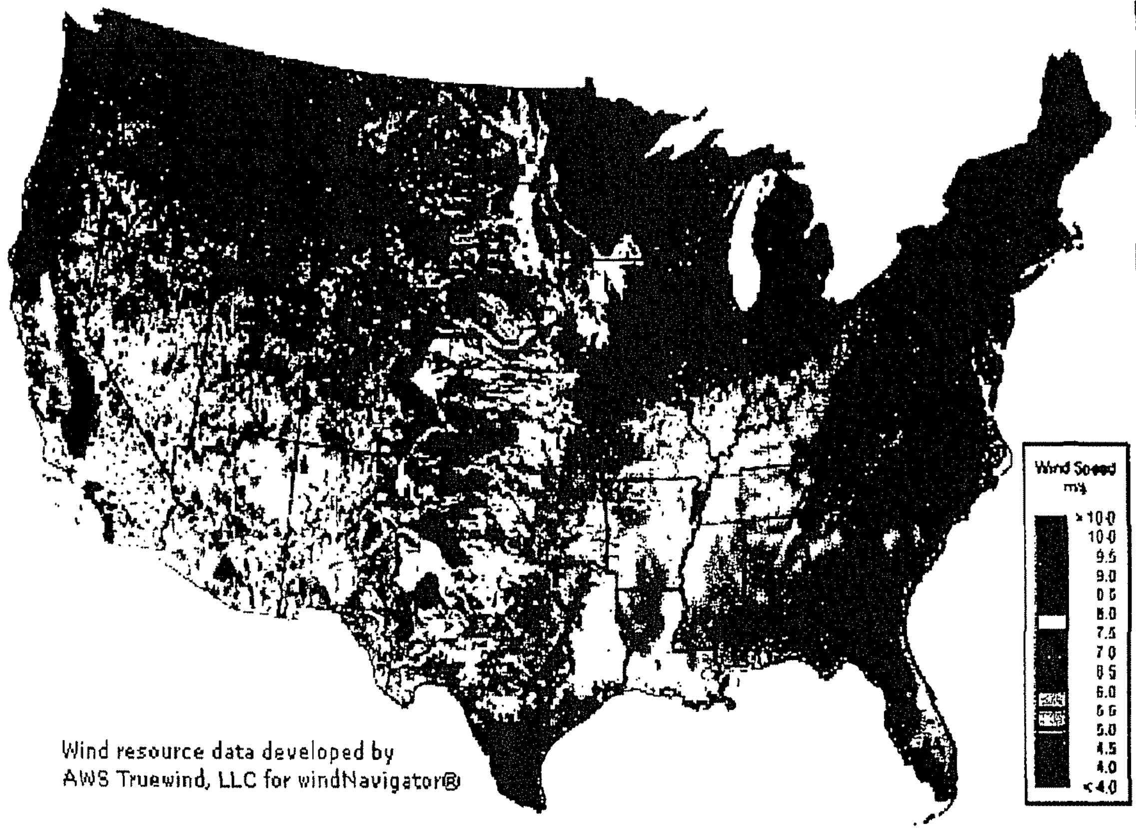
Wind is currently the fastest growing form of electricity generation in the world. Utility wind energy is generated by wind turbines with a range 1.0 to 2.5 MW, with a 1.5 MW turbine being the most common size used in commercial applications today with over 25,000 MW of wind online as of January 2010. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical from the perspective of both the existing wind resource and its proximity to a transmission system with available capacity.

Ultimately, as turbine production increases to match the significant increase in demand, the high capital costs of wind generation should begin to decline. Currently, the cost of electricity from wind generation is becoming competitive within the AEP-East zone due largely, however, to subsidies, such as the federal production tax credit as well as consideration given to REC values, anticipated rising fuel costs or future carbon costs.

A drawback of wind is that it represents a variable source of power in most non-coastal locales, with capacity factors ranging from 30 to 45 percent; thus its life-cycle cost ($/MWh), excluding subsidies, is typically higher than the marginal (avoided) cost of energy, in spite of wind's zero dollar fuel cost. Another obstacle with wind power is that its most critical factors (i.e., wind speed and sustainability) are typically highest in very remote locations, and this forces the electricity to be transmitted long distances to load centers necessitating the buildout of EHV transmission to optimally integrate large additions of wind into the grid. **Exhibit 6-3** shows the wind resource locations in the U.S. and their relative potential.

AMERICAN ELECTRIC POWER

Exhibit 6-3: United States Wind Power Locations

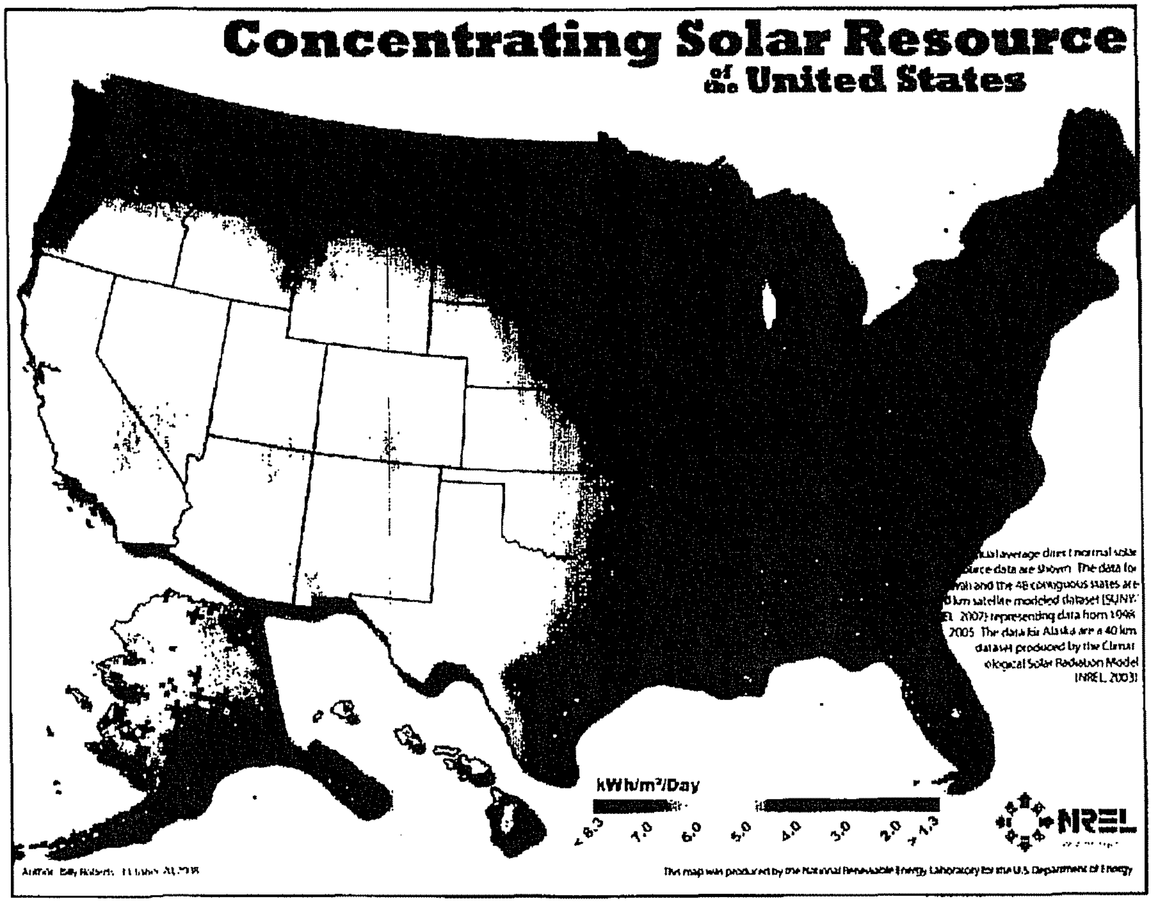


Source: U.S. Department of Energy

6.3.2 Solar

Solar power takes a couple of viable forms to produce electricity: concentrating and photovoltaics. Concentrating solar – which heats a working fluid to temperatures sufficient to power a turbine - produces electricity on a large scale (100 MW) and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (2 kW to 20 MW per installation) and are distributed throughout the grid. In the AEP-East zone, solar has applications as both large scale and distributed generation. The appeal of solar is broad and recent legislation in Ohio has made its pursuit mandatory subject to rate impacts, beginning in 2009. Solar photovoltaics are represented in this IRP as though this full solar requirement is to be met in Ohio. However, the amounts of solar prescribed in the law, while substantial, will not have a significant effect on the timing or amount of other supply assets within a ten-year planning period. **Exhibit 6-4** shows the potential solar resource locations in the U.S.

Exhibit 6-4: United States Solar Power Locations



Source: NREL

6.3.3 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials.

It is generally accepted that sustainably produced biomass represents a carbon neutral fuel. Carbon from the atmosphere is converted into biological matter by photosynthesis. Upon combustion, the carbon returns to the atmosphere as carbon dioxide (CO_2) where it can be recaptured by new biomass growth replacing the biomass used as fuel. Therefore a reasonably stable level of atmospheric carbon results from its use as a fuel.

In the United States today, a large percentage of biomass power generation is based on wood-derived fuels, such as waste products from the pulp and paper industry and lumber mills. Biomass from agricultural wastes also plays a dominant role in providing fuels. These agricultural wastes include rice and nut hulls, fruit pits, and manure.

A relatively low-cost option to produce electricity by burning biomass is by co-firing it with coal in an existing boiler using existing coal feeding mechanisms. In a typical biomass co-firing application, 1.5% to 6% of the generating unit's heat input is provided by biomass, depending on the boiler's method of firing coal. A more capital-intensive option is separate injection, which involves separate handling facilities and separate injection ports for the biomass. Separate injection can achieve a 10% heat input from biomass.

Co-firing generally provides a lower-cost method of energy generation from biomass than building a dedicated biomass-to-energy power plant. In addition, a coal-fired power plant typically uses a more efficient steam cycle and consumes relatively less auxiliary power than a dedicated biomass plant, and thus generates more power from the same quantity of biomass.

Some possible drawbacks associated with biomass co-firing or separate injection include reduced plant efficiencies due to lower energy content fuels, loss of fly ash sales, and fouling of SCR catalysts used to remove NO_X from the exhaust gas. Although these relatively minor obstacles can be mitigated through various means, the major obstacles to the utilization of biomass as a feedstock include volatile costs of transportation and substitute uses for the fuel. Biomass has many competing demands, such as the pulp and paper markets, agriculture industries, and the ethanol market, which can dramatically escalate the market price for the material along with the transportation of such a low energy-density fuel. Another issue associated with biomass is the significant quantities of dedicated land necessary to generate sufficient quantities of biomass as identified in **Exhibit 6-5**.

Exhibit 6-5: Land Area Required to Support Biomass Facility

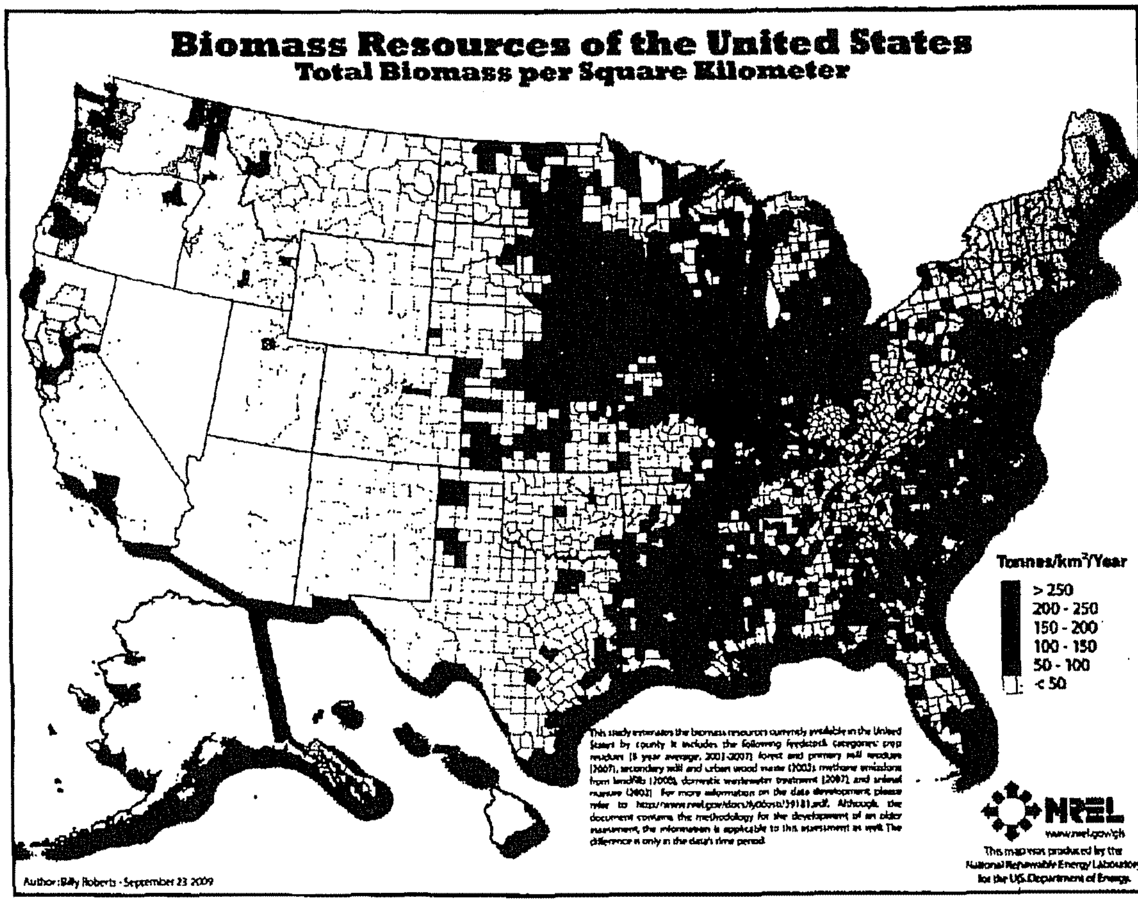
Switchgrass	Wood Chips / Sawdust
(per Purdue University Study) o 6 -to- 8 tons /yr. per acre yield o @ 6700 Btu/lb (non-dried, as harvested) *A 200-MW Dedicated Biomass Facility* *(70% C.F.) would require…* **110k -to- 150k harvested acres** *(172 - 234 sq. mi,)* *[illegible] of switchgrass-fired biomass capacity [illegible] approx* ***45 MM t/yr. of switchgrass*** *which [illegible] dedicated agri-land mass =* ***6.5 MM acres*** *[illegible] cropland and pasture/grassland [illegible] USDA in the state of* **Georgia**	*(per AEP-Forestry)* o 70 -to-100 tons /yr. per acre yield* * "clear cutting" on a <u>*40-year cycle*</u> o @ 4800 Btu/lb (green, non-dried) *A 200-MW Dedicated Biomass Facility* *(70% C.F.) would require…* **510k -to- 730k timbered acres** *(795 - 1,140 sq. mi,)* ***10-GW*** *of (clear-cut) wood chip-fired capacity would require approx.* ***64 MM t/yr. of wood product*** *which would require dedicated forested-land mass =* ***31 MM*** *acres … or 100% of the forested acreage identified by the USDA in* **North Carolina** *and* **South Carolina combined**

Source: AEP Resource Planning

Biomass utilization provides many valuable benefits and holds some promise for the AEP generating fleet, but the high fuel/transportation costs and the limited deployment potential on a heat-input basis inhibits the near-term viability of the technology on a large scale. **Exhibit 6-6** shows potential biomass resources.

Biomass utilization is not a substitute for additional generation. Because it simply substitutes "carbon-neutral" fuel for fossil fuels, it does not eliminate the need for building generation as demand grows and assets are retired. However, if and when GHGs become regulated, biomass co-firing could become an economically viable way to reduce the CO_2 output of certain coal-fired plants.

Exhibit 6-6: Biomass Resources in the United States



Source: NREL

6.3.4 Renewable Energy Certificates (RECs)

An additional option for complying with renewable standards involves the purchase of renewable energy certificates, or "RECs". RECs are generated contaminant with carbon-neutral energy, but are sold separately providing the energy produced is sold into the relevant grid. This arrangement allows for efficient transfer of costs from over-producers to under-producers of required carbon-neutral energy. In nascent markets, where over-production does not exist, RECs will be scarce or non-existent, driving values high. High REC values, in turn, will foster additional capital investment, until REC values reach equilibrium.

In AEP-East zone states with renewable requirements (Ohio and Michigan), REC markets exist or are developing for renewable (in-state and deliverable) and solar (in-state and deliverable) but are not yet reliable sources for compliance.

6.3.5 Renewable Alternatives—Economic Screening Results

AEP has established an internal renewable target of 10% of System energy (total East and West zones) from renewable resources by 2020 (see **Appendix E**). Based on current AEP renewable resources, and considering an additional 1,000 MW of renewable resources committed to by the year-end 2014, together with the prospective renewable projects listed in **Exhibit 6-7**, included in the 2010 IRP (AEP-East and SPP), this internal commitment is projected to be satisfied. Note that the 2014 target represents an approximate 3-year shift in prior (2009 IRP) planned commitments of 2,000 MW of System-wide renewable resources by the end of *2014*; however, as recent unfavorable regulatory decisions in both Virginia and Kentucky surrounding cost recovery of planned wind purchase transactions has resulted in this "extension" of that prior goal.

Exhibit 6-7: Renewable Sources Included in AEP-East and AEP-SPP 2010

AEP-System
Existing and Projected Renewables for 2010 IRP

Unit, Plant, or Contract	Unit Type: Solar	Unit Type: Wind	Unit Type: Biomass	Size (MW)	First Full Energy Year	Renewable as % of Sales	Notes
Wind (SW Mesa)		X		31	Existing	0.1%	Existing (RECs only)
Wind (Weatherford)		X		147	Existing	0.5%	Existing
Wind (Blue Canyon II)		X		151	Existing	0.9%	Existing (RECs only until 2013)
Wind (Sleeping Bear)		X		95	Existing	1.2%	Existing
Wind (Camp Grove)		X		75	Existing	1.4%	Existing
Wind (Fowler Ridge I & III)		X		200	2010	1.8%	Executed PPA
Wind (Grand Ridge II & III)		X		101	2010	2.0%	Executed PPA
Wind (Fowler Ridge II)		X		150	2010	2.4%	Executed PPA (Add'l take)
Wind (Majestic)		X		80	2010	2.6%	Executed PPA (RECs only until 2012)
Wind (Blue Canyon V)		X		99	2010	2.9%	Executed PPA (RECs only until 2013)(Add'l take)
Wind (Beech Ridge)		X		101	2011	3.1%	Executed PPA(PSC-Apprvd)
Wind (Elk City)		X		99	2011	3.3%	Executed PPA (RECs only until 2013)(Add'l take)
Solar (Wyandot)	X			10	2011	3.4%	Executed PPA
Solar (Ohio)	X			10	2011	3.4%	w/ ITC
Biomass (Ohio units)			X	44	2011	3.5%	Ohio Units 10% Co-Fire
Wind (East)		X		100	2012	3.6%	w/ PTC
Wind (Minco)		X		100	2012	3.9%	Minco (PSO)
Solar (Ohio)	X			10	2012	3.9%	w/ ITC
Wind (East)		X		100	2013	4.1%	w/ PTC
Solar (Ohio)	X			10	2013	4.1%	w/ ITC
Biomass (East)			X	50	2014	4.4%	RECs PPA or Unit Co-Fire (No New Capacity)
Wind (East)		X		300	2014	5.0%	No PTC
Solar (Ohio)	X			26	2014	5.0%	w/ ITC
Wind (East)		X		400	2015	5.9%	No PTC
Wind (West)		X		200	2015	6.4%	No PTC
Solar (Ohio)	X			26	2015	6.4%	w/ ITC
Solar (Distributed)	X			25	2015	6.5%	(E&W) No ITC
Biomass (Ohio units)			X	(44)	2016	6.3%	Retirement of Ohio Units 10% Co-Fire
Wind (West)		X		200	2016	6.9%	No PTC
Wind (East)		X		250	2016	7.4%	No PTC
Solar (Ohio)	X			26	2016	7.4%	No ITC
Wind (West)		X		200	2017	7.9%	No PTC
Wind (East)		X		150	2017	8.2%	No PTC
Solar (Ohio)	X			26	2017	8.3%	No ITC
Solar (Ohio)	X			26	2018	8.3%	No ITC
Wind (East)		X		50	2018	8.4%	No PTC
Biomass (East)			X	100	2018	8.9%	RECs PPA or Unit Co-Fire (No New Capacity)
Wind (East)		X		100	2019	9.1%	No PTC
Solar (Ohio)	X			26	2019	9.1%	No ITC
Wind (West)		X		300	2020	9.9%	No PTC
Wind (East)		X		150	2020	10.2%	No PTC
Solar (Ohio)	X			26	2020	10.2%	No ITC

Source: AEP Resource Planning

6.4 Demand-Side Alternatives

6.4.1 Background

Demand Side Management refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. Programs or tariffs that reduce consumption at the peak are demand response (DR) programs, while round-the-clock measures are energy efficiency (EE) programs. The distinction between peak demand reduction and energy efficiency is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

6.4.2 Demand Response

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. In AEP's respective East (PJM) zone, this maximum (System peak) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. This can be addressed several ways via both "active" and "passive" measures:

- *Interruptible loads.* This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.
- *Direct load control.* Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates.* Offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) and to as often as 15-minute increments known as "real-time pricing". Accomplishing real-time pricing requires digital (smart) metering.

- *Energy Efficiency measures.* If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less. This represents a "passive" demand response.
- *Line loss mitigation.* A line loss results during the transmission and distribution of power from the generating plant to the end user. To the extent that these losses can be reduced, less energy is required from the generator.

What may be apparent is that, with the exception of Energy Efficiency measures, the amount of power consumed is not typically reduced. Less power is consumed at the peak, but to accomplish the same amount of work, that power will be consumed at some point during the day. If rates encourage someone to avoid running their dishwasher at four, they will run it at some other point in the day. This is also referred to as load shifting.

6.4.3 Energy Efficiency

EE measures save money for customers billed on a "per kilowatt-hour" usage basis. The trade-off is the reduced utility bill for any up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him back in the form of reduced bills over an acceptable period, he will adopt it.

EE measures include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances, most commonly. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will, in all cases, reduce the amount of energy consumed but may have limited effectiveness at the time of peak demand. Energy Efficiency is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. According to a March 2007 DOE study such benefits include:

- Economics: Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
- Environment: Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change.
- Infrastructure: Lower demand lessens constraints and congestion on the electric transmission and distribution systems
- Security: Energy Efficiency can lessen our vulnerability to events that cut off energy supplies

However, market barriers to Energy Efficiency exist for the customer/participant.

Market Barriers to Energy Efficiency	
High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of energy efficiency options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for energy efficiency services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the energy efficiency measure may be different from those benefiting from the investment (e.g. rental property)
Product/Service Unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of market transformation and measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding demand-side resources in 2011 that are incremental to approved or mandated programs.

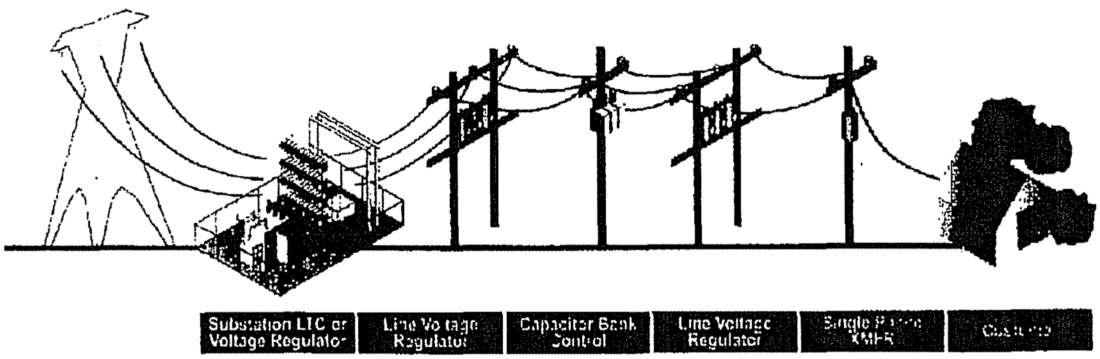
6.4.4 Distributed Generation

Distributed generation refers to (typically) small scale customer-sited generation downstream of the customer meter. Common examples are combined heat and power (CHP), residential solar applications, and even wind. Currently, these sources represent a negligible component of demand-side resources as even with available Federal tax credits, they are typically not economically justifiable.

6.4.5 Integrated Voltage/VaR Control

IVVC provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, IVVC enables conservation voltage reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. A 1% reduction in voltage typically results in a 0.5% to 0.7% reduction in load.

Exhibit 6-8: Integrated Voltage/VaR Control



6.4.6 Energy Conservation

Often used interchangeably with efficiency, conservation results from foregoing the benefit of electricity either to save money or simply to reduce the impact of generating electricity. Higher rates for electricity typically result in lower consumption. Inclining block rates, or rates that increase with usage, are rates that encourage conservation.

7.0 Evaluating DR/EE Impacts for the 2010 IRP

7.1 Demand Response/Energy Efficiency Mandates and Goals

The Energy Independence and Security Act of 2007 ("EISA") requires, among other things, a phase-in of lighting efficiency standards, appliance standards, and building codes. The increased standards will have a discernable effect on energy consumption. Additionally, legislative and/or regulatory mandated levels of demand reduction and/or energy efficiency attainment, subject to cost effectiveness criteria, are in place in Ohio, Indiana and Michigan in the AEP-East Zone. The Ohio standard, if cost-effective criteria are met, will result in installed efficiency measures equal to over 20 percent of all energy otherwise supplied by 2025. Indiana's standard achieves installed efficiency reductions of 13.90% in 2020 while Michigan's standard achieves 10.55%. Virginia has a voluntary 10% by 2020 target. While no mandate currently exists in Kentucky, KPCo has offered DR/EE programs to customers since the mid-1990's.

As identified in this document and in the Company's 2010 Corporate Accountability Report, AEP has internally committed to system-wide peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh, approximately 60-65% of which is in the AEP-East zone.

7.2 Current DR/EE Programs

As of June 1, 2010, active energy efficiency programs exist in Kentucky, Ohio, Michigan, with additional programs filed in Indiana and West Virginia. Demand response programs, consisting of interruptible tariffs, time differentiated rates, and load control, are currently being offered. The demand and energy impacts of the installed programs (as of March 31, 2010) are shown in **Exhibit 7-1. Appendix G** lists annual energy efficiency programs and demand reduction forecasts by operating company, by year.

Exhibit 7-1: AEP-East Embedded DR/EE Programs

[illegible]					
	Energy Efficiency	Interuptible	ATOD	Total	Energy Efficiency
Ohio	38	140	0	178	305
APCo	0	14	107	121	0
I&M	2	258	0	260	8
Kentucky	3	0	0	3	4
AEP-East	43	412	107	562	317

Source: AEP Resource Planning

7.2.1 gridSMART Smart Meter Pilots

Smart meter pilots are underway in Indiana and Ohio. As of June 1st, 2010, nearly 200,000 customers have been equipped with the new meters. The meters allow for time-differentiated pricing which should result in more efficient customer use of electricity and peak usage reductions.

AEP's first gridSMART pilot program began in 2009 in South Bend, Indiana. The year-long South Bend pilot involved approximately 10,000 meters and was to end after the 2009 cooling season, but it has been extended to include the 2010 cooling season because of some early technical problems.

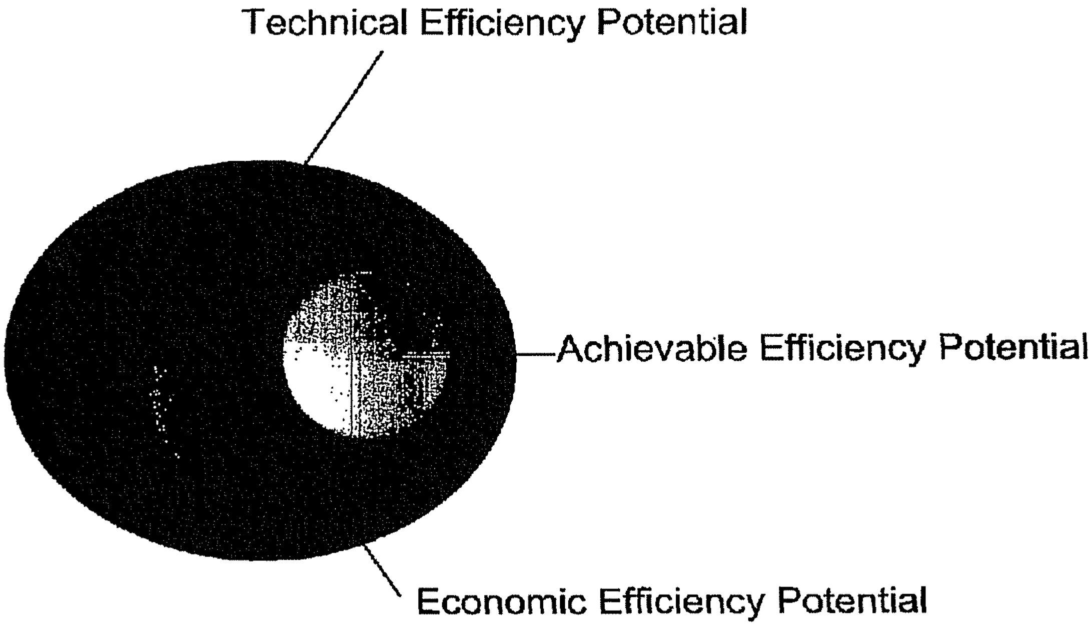
A larger and more comprehensive gridSMART demonstration project involves 110,000 customers in central Ohio. Paid for in part with a $75M grant from the DOE, the $150M project will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart appliances and home energy management systems, a new cyber security center, PHEV (Plug-in/hybrid electric vehicle) demonstrations, and installation of utility-activated control technologies that will reduce demand and energy consumption without requiring customers to take action. This last technology is known as such as Integrated Voltage VaR Control (IVVC), a form of voltage control that allows the grid to operate more efficiently. In IVCC, sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor (Var flow) and voltage levels. Power factor optimization improves energy efficiency by reducing losses on the system. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, enabling consumers to use less energy without any changes in behavior or appliance efficiencies. Early results indicate a range of 0.5% to 1% of energy demand reduction for a 1% voltage reduction is possible.

The results of these pilots will greatly inform the impacts assigned to larger roll-outs of these meters and related projects such as IVVC, should they ultimately be approved. It is still unknown how much deployment of these meters will change customer consumption patterns relative to traditional meters. As these behaviors become discernible and quantifiable, their effects will be incorporated into future load forecasts and IRPs.

7.3 Assessment of Achievable Potential

The amount of Energy Efficiency and Demand Response that are available are typically described in three buckets: technical potential, economic potential, and achievable potential. For states that do not have mandates in place, DR/EE savings were developed using an achievable potential target (**Exhibit 7-2**).

Exhibit 7-2: Achievable versus Technical Potential (Illustrative)



Source: AEP Resource Planning

Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, cost-effectiveness. The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic. This compares the avoided cost savings achieved over the life of a measure/program with its cost to implement it, regardless of who paid for it. The third set of efficiency assets is that which is achievable.

Of the total potential, only a fraction is achievable and only then over time due to the existence of market barriers. How much effort and money is deployed towards removing or lowering the barriers is a decision made by state governing bodies.

States with legislative or regulatory requirements universally require that these requirements be met economically and provide for "off ramps" if or when pursing the goals no longer meets that criterion. "Economic potential" is estimated to be in the 20-25% range of total consumption. The "achievable" range is a fraction of the economical range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards. Both amounts are represented in this IRP as reductions to what would otherwise be the load forecast.

7.4 Utility-sponsored DSM modeling/forecasting

Two sources were used as the basis for the analysis in this IRP. The first source is an AEP Measures Database that was specifically developed for AEP and its jurisdictions as part of its DSMore software package. DSMore, an industry-standard software tool, analyzes DR/EE programs and produces test results in line with DR/EE industry standards. The AEP Measures Database was used to determine which measures would be modeled in the current IRP. The second is a national energy efficiency study published by the Electric Power Research Institute (EPRI) in January of 2009. This study defines realistically achievable EE target levels. It estimates a cumulative achievable target of 3.3% EE savings by 2020 relative to a baseline forecast which includes the effects of the increased standards required in EPAct 2007.

7.4.1 DSM Proxy Resources

The DSMore Measures Library was used to find viable measures by Residential and Commercial class for the IRP. Measures were organized into groups and then evaluated based on their Total Resource Cost Test (TRC) scores. The TRC measures the net costs of a EE program as a resource option based on the total costs of the program, including both the participant's and the utility's costs. Aggregate blocks were considered viable and chosen for optimization modeling only if their TRC scores were above 1.00 except for Residential Low and Moderate Income Weatherization. Because these programs are typically required in jurisdictions where energy efficiency is being implemented, its costs and impacts were included outside of the optimization process. As such, the following measure blocks were chosen.

Exhibit 7-3: DSM Proxy Resources Costs

Measure	*Levelized Resource Cost \$/kWh*[6]	*Levelized Program Cost \$/kWh*[1]	*TRC Score*
C& I Lighting	***.059***	***.033***	***1.05***
C&I Pumps & Motors	***.040***	***.023***	***1.53***
Residential Lighting	***.033***	***.019***	***1.86***
Residential Water Heating	***.034***	***.019***	***2.39***
Residential Low Income	***.070***	***.070***	***0.86***
C&I Demand Response[7]	***N/A***	***N/A***	***1.8***
IVVC[8]	***.034-.047***	***.034-.047***	***2.1-2.5***

Source: AEP Resource Planning

These blocks served as proxy resources for the actual programs that will, over time, be implemented. The blocks have individual characteristics or load shapes. It is desirable that, in

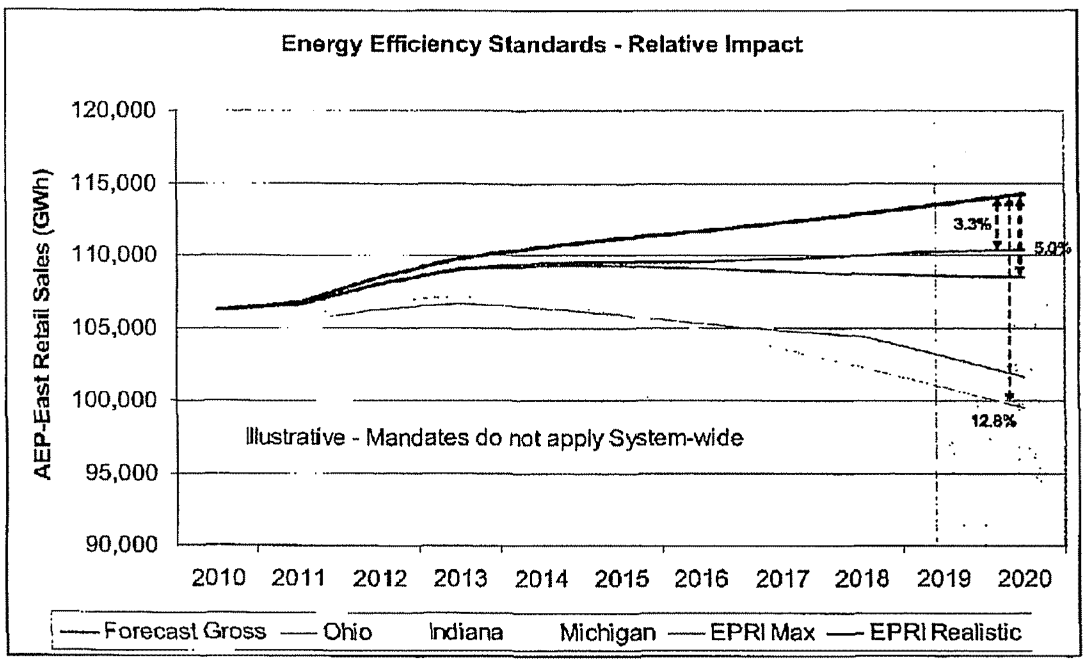
6 Non-discounted
7 Assumes no energy savings from demand interruptions
8 Blocks are non-homogeneous

aggregate. the blocks will have similar characteristics to what eventually gets implemented so that the remainder of the supply-side optimization is accomplished with reasonably accurate demand-side interrelationships.

7.4.2 DSM Levels

Energy usage and energy savings amounts for states that did not have pre-existing mandates were made based on EPRI's January 2009 study. The EPRI study, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.*, "documents the results of an exhaustive study to assess the achievable potential for energy savings and peak demand reduction from [utility-sponsored] energy efficiency and demand response programs." EPRI further defines the "achievable potential" as an estimated range of savings attainable through programs that encourage adoption of energy efficient technologies, taking into consideration technical, economic, and market conditions. The study differentiates what these programs can achieve prospectively from what may occur through the natural adoption of efficiency by consumers, either through preferences or codes and standards. The EPRI study provides a useful basis for assigning realistic levels of energy efficiency and demand response in lieu of jurisdiction-specific studies as well as a basis for assessing jurisdiction-specific study results which are typically stated as a range of possible outcomes. It is noteworthy that the mandates in Ohio and Indiana exceed what EPRI has determined is realistic or even possible by 2020. While conflicting, this outcome is possible if the jurisdictions involved are willing to exceed the funding levels envisioned as maximums by EPRI; it is on this basis that mandates were assumed to be met through 2020.

Exhibit 7-4: Energy Efficiency Impacts



Source: AEP Resource Planning

The use of these proxy resources is necessary to model supply-side and demand-side resources within the same optimization process. In no way does this process imply that these programs, in their current form and composition must be done in equal measure and in all jurisdictions. All states are different and may have specific rules regarding the ability of C&I customers to "opt out" of utility programs, influencing the ultimate portfolio mix. Some states have a collaborative process that can greatly influence the tenor and composition of a program portfolio. These blocks provide a reasonable proxy for demand-side resources within the context of an optimization model.

7.5 Validating Incremental DR/EE resources

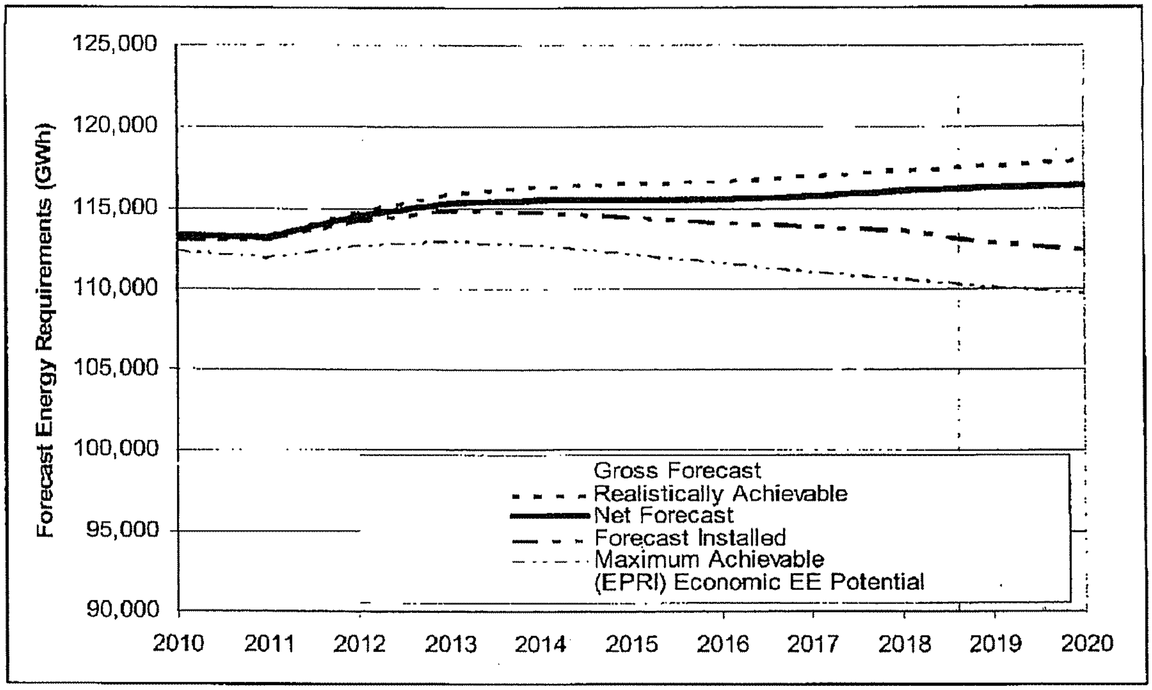
7.5.1 Energy Efficiency

Energy Efficiency resource blocks were made available within the *Strategist* model with annual constraints by program and in total. These constraints keep the resource modeling process from selecting DR/EE resources faster than is practical in non-mandated states. The result of the constraints is a roll out of programs that is consistent with the EPRI realistically achievable level of demand side resources.

Since the blocks were prescreened for cost-effectiveness, this process merely validates the incremental resources within the supply optimization. As a practical matter, actual EE programs are likely to contain elements of many of these programs but not match the blocks exactly. However, for the purposes of validating the cost-effectiveness of demand options, and quantifying the benefits relative to supply options, the proxy demand resources are suitable.

Exhibits 7-5 through 7-7 show the net forecast with relevant benchmarks. The forecasted DSM levels exceed the EPRI realistically achievable level due to aggressive requirements in Ohio, Michigan and Indiana.

Exhibit 7-5: AEP -East Energy Efficiency Program Assumptions



Source: AEP Resource Planning

Results:

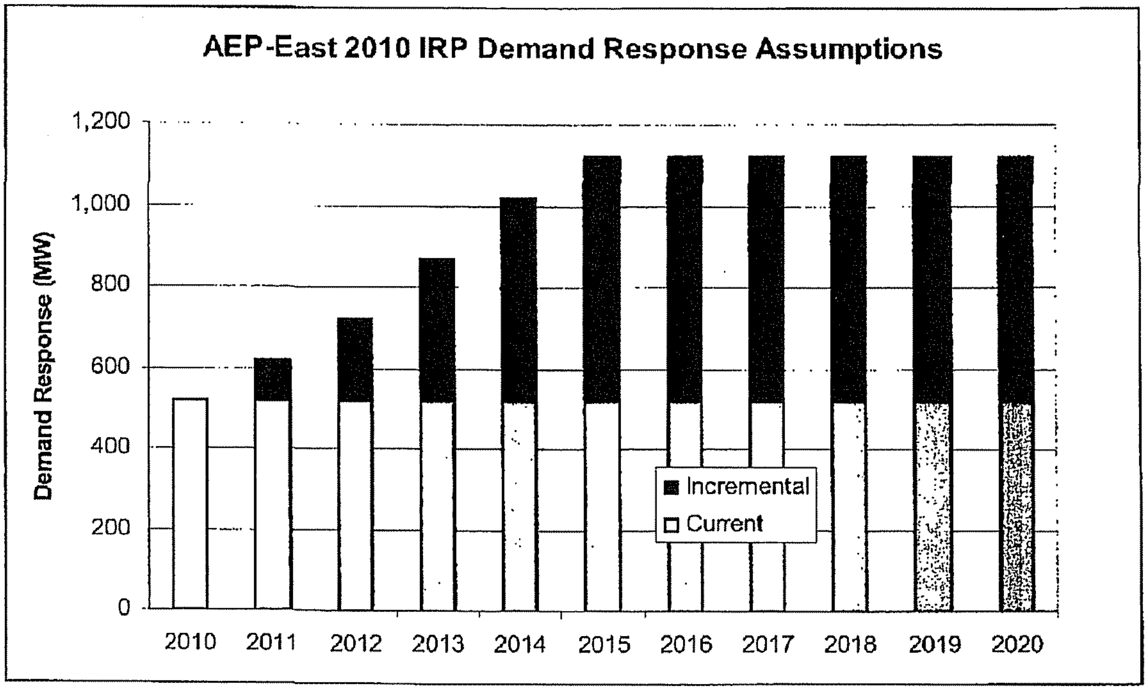
By 2020, as a result on energy efficiency programs, peak demand is reduced by 873 MW in the AEP-East zone; consumption is reduced by 5,602 GWh.

7.5.2 Demand Response

The demand response resource blocks were made available within the *Strategist* model with annual constraints by program and in total. These resources are incremental to the tariff-based demand response that is currently in place. The results are consistent with levels for demand response in the EPRI study.

Currently, given the extensively long capacity position in AEP-East, the addition of incremental DR, while having value relative to PJM, may have limited value to the AEP-East System given the current cap limitation in the supplementary auction of 1,300 MW. AEP's inability to realize the full PJM value might hinder cost recovery in some or all jurisdictions. However, incremental DR may include the added flexibility to effect peak reductions at the Operating Companies, providing desirable concomitant value within the AEP-East System Pool. Additionally, demand response capabilities are being aggressively cultivated by FERC, RTOs, and some states. Given that background, and uncertainty surrounding potential EPA HAP rules, it is reasonable to continue pursuit of a robust demand response capability which would include (AEP customer) assets that are currently committed to PJM through independent third-party curtailment service providers (CSPs).

Exhibit 7-6: AEP -East Demand Response Assumptions

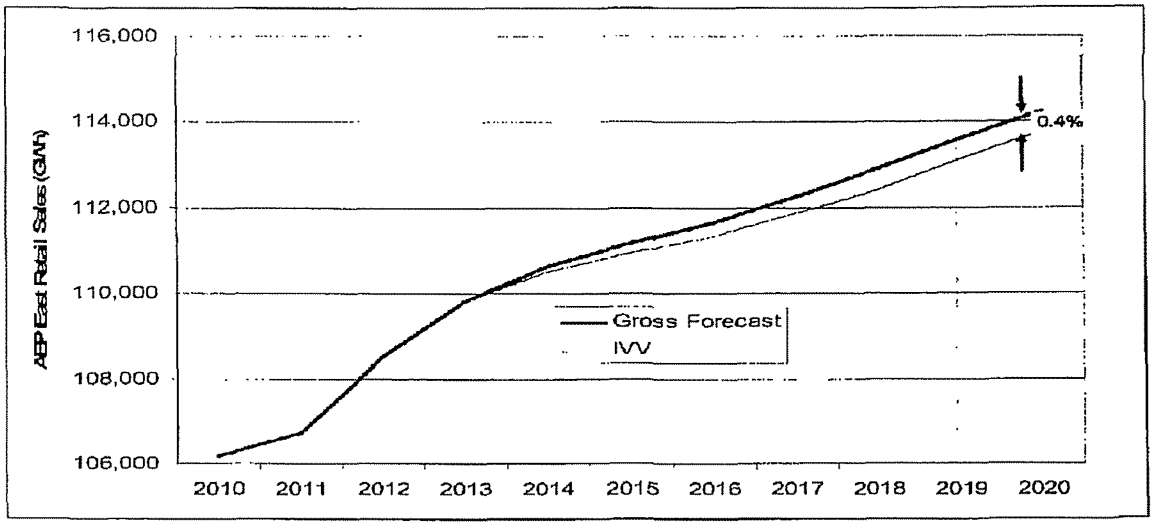


Source: AEP Resource Planning

7.5.3 IVVC

IVVC blocks varied in cost effectiveness. *Strategist* was able to pick the most promising project blocks first and add subsequent blocks when it was economical to do so. In the AEP-East System, blocks became economic beginning in 2014. Five of the available seven blocks were ultimately selected.

Exhibit 7-7: AEP -East IVV Response Assumptions



Source: AEP Resource Planning

7.6 Discussion and Conclusion

The assumption of aggressive peak demand reduction and energy efficiency achievement reflect not only legislative and regulatory mandated levels of DR/EE in Indiana, Ohio, Michigan, Oklahoma and Texas but AEP's sytem-wide commitment to demand-side resources in other jurisdictions.

The amount of DR/EE included in this Plan is higher than past IRP plans have included. There are a few reasons why this is valid:

- Mandates at the state and potentially at the federal level will encourage adoption of demand side resources at a pace higher than would have been reasonably forecast in the past. Indiana enacted a high mandate this year which requires cumulative energy savings of 13.9% by 2020.
- Increased awareness and acceptance of the purported link between global climate change and the consumption of fossil fuels will drive increased adoption of conservation measures, independent of economic benefit.
- Increased interest in demand response from the introduction of emergency capacity programs from PJM. Because AEP-East has historically not been able to count the demand assets of customers who participate in the PJM program, the Company seeks to broaden its interruptible tariffs to accommodate customers who have previously not been eligible, primarily because of size.
- In states without existing legislative or regulatory mandates, the level of DR/EE is consistent with EPRI's "realistically achievable" levels. Where these levels are exceeded in states with mandates, it is reasonable to expect compliance with those mandates, albeit at potentially high costs.

The mechanism for regulatory cost recovery and the appetite for utility-sponsored DR/EE is formalized through the legislative and ratemaking processes in the various jurisdictions in which AEP operates, the amount and type of DR/EE programs will likely change by jurisdiction to reflect the environment. Executing this plan will enable AEP to fulfill its system-wide commitment of 1,000 MW of demand reduction capability and 2,250 GWh of energy efficiency by 2012.

The following **Exhibit 7-8** summarizes the AEP-East EE assumptions for the 2010 IRP. The data is split by "Net" and "Installed". "Installed" indicates the annualized impacts of DSM measures at the time of installation while "Net" reflects the expected impact. It is less than the installed impact due to assumptions about the timing of the installation (partial year savings), measure fade (measures failing and not being replaced) and "snap back" (the use of saved energy for other purposes).

Installation of these measures is predicated on securing adequate cost recovery. For this planning cycle, it is assumed that such recovery would be forthcoming. For the 10 year planning horizon, this level of DSM still closely matches the EPRI Realistically Achievable.

Exhibit 7-8: Incremental Demand-Side Resources Assumption Summary

[illegible]				
	Installed		Net	
	GWh	MW	GWh	MW
2010	233	38	91	16
2011	900	149	683	107
2012	1,592	266	1,266	200
2013	2,385	404	1,897	304
2014	3,294	563	2,560	416
2015	4,249	708	3,215	505
2016	5,091	844	3,676	573
2017	5,971	988	4,069	631
2018	6,887	1,136	4,408	680
2019	8,383	1,392	4,967	768
2020	9,487	1,593	5,602	873

IVVC				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	136	20	136	20
2015	253	53	253	53
2016	338	70	338	70
2017	423	88	423	88
2018	509	105	509	105
2019	509	106	509	106
2020	509	105	509	105

Demand Response				
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	100	0	100
2012	0	200	0	200
2013	0	350	0	350
2014	0	500	0	500
2015	0	600	0	600
2016	0	600	0	600
2017	0	600	0	600
2018	0	600	0	600
2019	0	600	0	600
2020	0	600	0	600

[illegible]				
	Installed		Net	
	GWh	MW	GWh	MW
2010	233	38	91	16
2011	900	249	683	207
2012	1,592	466	1,266	400
2013	2,385	754	1,897	654
2014	3,429	1,084	2,696	936
2015	4,502	1,361	3,468	1,158
2016	5,429	1,514	4,015	1,244
2017	6,394	1,676	4,493	1,319
2018	7,395	1,842	4,917	1,385
2019	8,891	2,098	5,475	1,474
2020	9,996	2,298	6,111	1,578

Source: AEP Resource Planning

8.0 Fundamental Modeling Scenarios

8.1 Modeling and Planning Process—An Overview

A chart summarizing the IRP planning process, identifying the fundamental input requirements, major modeling activities, and process reviews and outputs, is presented in **Exhibit 8-1.** Given the diverse and far-reaching nature of the many elements as well as participants in this process, it is important to emphasize that this planning process is naturally a **continuous, evolving activity.**

In general, assumptions and plans are continually reviewed and modified as new information becomes available. Such continuous analysis is required by multiple disciplines across AEP to ensure that: market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are constantly reassessed to ensure optimal capacity resource planning.

Further impacting this process are growing numbers of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers (including Ohio customers) represents one of the cornerstones of this 2010 AEP-East IRP process. Therefore, as a result, the "objective function" of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

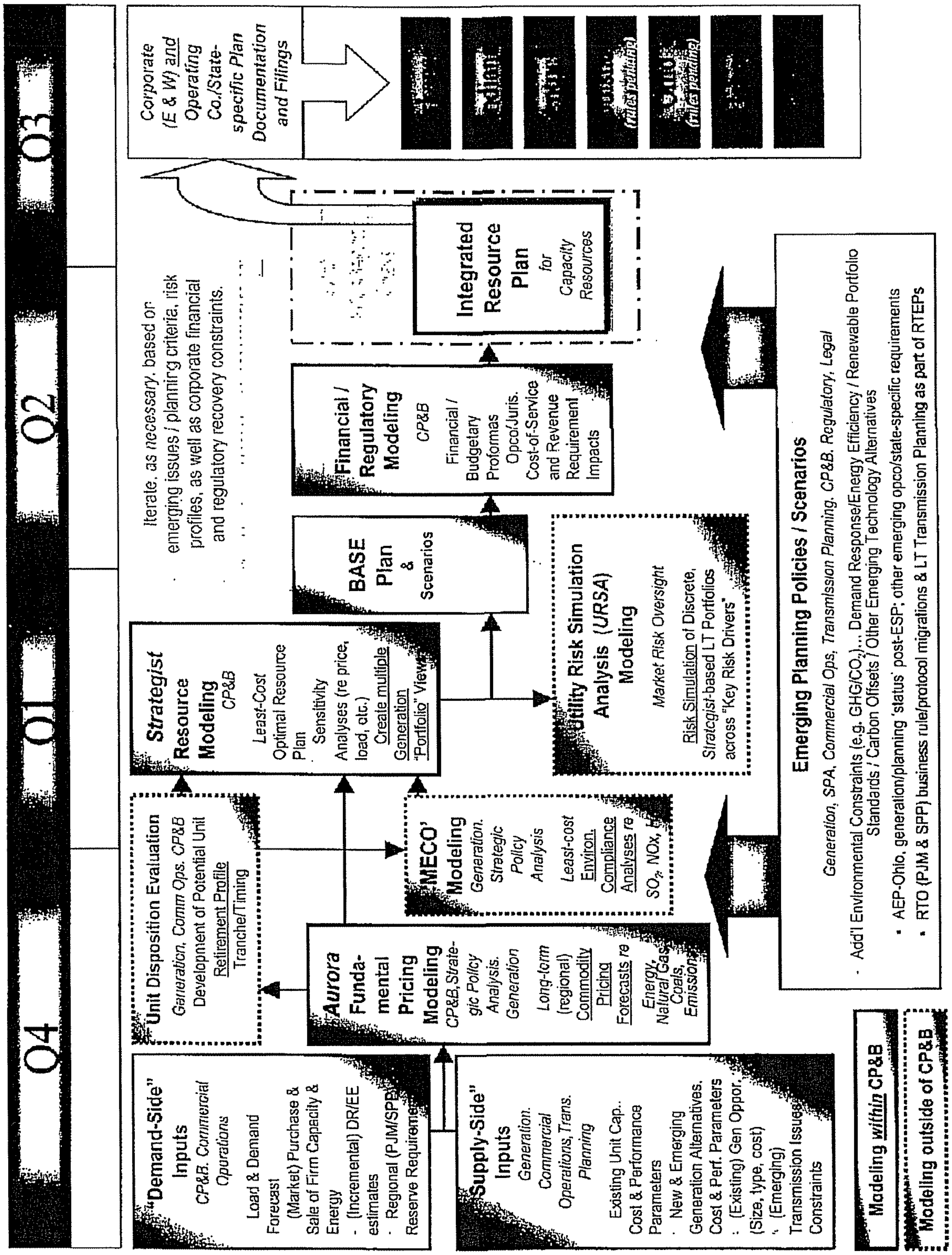
That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. As discussed in this (and prior) section, other factors–some more difficult to quantify than others–were considered in the determination of the AEP-East Integrated Resource Plan (IRP). To challenge the robustness of the Plan, sensitivity analyses were performed to address these factors.

8.2 Methodology

The IRP process aims to address the long-term "gap" between resource needs and current resources (**Section 5**). Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Strategist*[9] is the primary modeling application used by AEP for identifying and ranking portfolios that address the gap between needs and current available resources. Given the set of proxy resources–both supply and demand side–and a scenario of economic conditions that include fuel prices, capacity costs, energy costs, effluent prices including CO_2, and demand, *Strategist* will return all combinations of the proxy resources (portfolios) that meet the resource need. The portfolios are ranked on the basis of cost, or cumulative present worth (CPW), of the resulting stream of revenue requirements. The least cost option was considered the initial "optimum" portfolio for that unique input parameter scenario.

[9] A proprietary long-term resource optimization tool of Ventyx - an ABB company - utilized extensively in the utility industry for over two decades.

Exhibit 8-1: IRP Modeling and Planning Process Flow Chart



Source: AEP Resource Planning

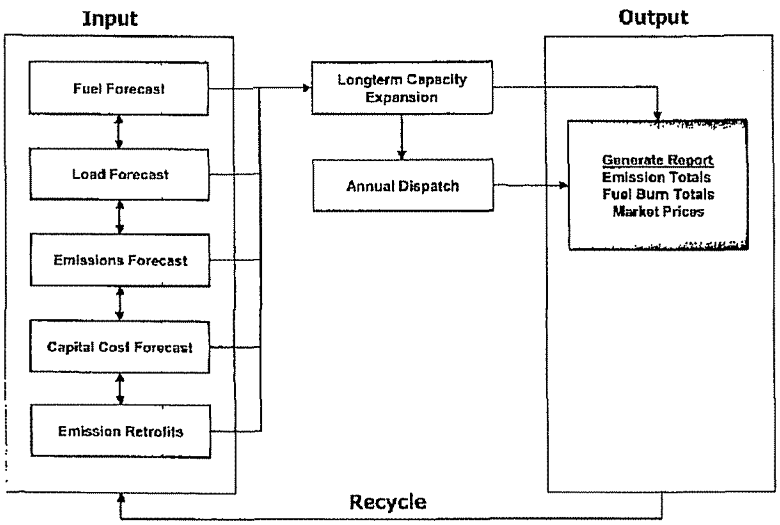
8.3 Key Fundamental Modeling Pricing Scenarios

This section includes excerpts from the "Long Term Forecast 2010-2030: Consumer Choice: A Time to Choose. 2H-2009" *prepared by AEPSC's Strategic & Economic Analysis (SEA) organization and issued February 2010.*

The AEP-SEA long-term power sector suite of commodity forecasts are derived from the Aurora model. Aurora is a fundamental production-costing tool that is driven by inputs into the model, not necessarily past performance. AEP-SEA models the eastern synchronous interconnect and ERCOT using Aurora. Fuel and emission forecasts established by AEP Fuel, Emissions and Logistics, are fed into Aurora. Capital costs for new-build generating assets by duty type are vetted through AEP Engineering Services. The CO_2 forecast is based on assumptions developed by AEP Strategic Policy Analysis.

Exhibit 8-2 shows the AEP-SEA process flow for solution of the long-term (power) commodity forecast. The input assumptions are initially used to generate the output report. The output is used as "feedback" to change the base input assumptions. This iterative process is repeated until the output is congruent with the input assumptions (e.g., level of natural gas consumption is suitable for the established price and all emission constraints are met).

Exhibit 8-2: Long-term Forecast Process Flow



Source: AEP SEA

In this report, four distinct scenarios were developed: the "Reference Case", "Business As Usual (BAU) Case", "Stagnation", and "Altruism Case". The scenarios are described below:

Reference – The point of the label "Reference" is not because it is the most likely outcome. It is labeled Reference because it represents what we have typically done in the company – use Moody's Economy.com as the economic outlook. As compared to previous reference cases, the start of carbon policies have been moved up to 2014 versus 2015, indicating an increased likelihood of a policy. The carbon treatment policy follows a "Waxman-Markey" like policy, except starting in 2014 versus 2012.

Business As Usual (BAU) – As the title of this case suggests, it assumes there is no change from 2009. This includes no change in environmental policies such as carbon. The economic outlook in this scenario is identical to the Reference economic profile other than there is no economic impact observed in 2014 due to carbon policies. This scenario is probably the least likely given that nothing changes, but it certainly is the easiest to conceive because everything is known.

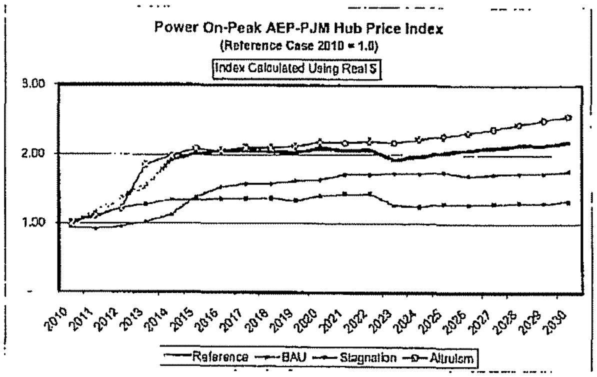
Stagnation – Concerns of rising government debt and no clear path for the transformation of the economy from less consumer driven results in a stagnated economy similar to Japan's experience. Much like Japan, the country continues to prop up insolvent banks. Optimistically, the U.S. will react faster and remember lessons learned so that stagnation lasts only five years versus Japan's decade plus.

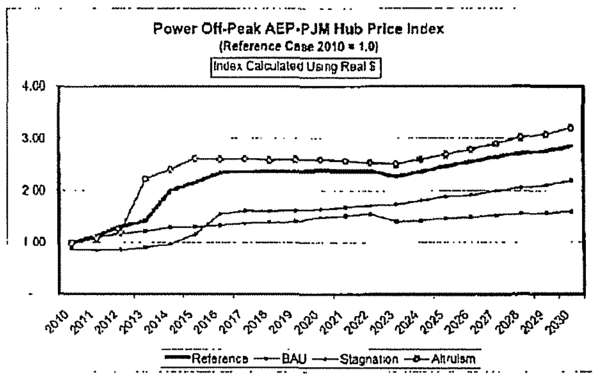
Altruism – This scenario is the hardest to imagine and construct. There is a united front across the majority of the world for the reduction of carbon. There is one carbon price accepted by all so no major wealth transfers occur. If this assumption did not occur, we could see mass economic shifting as corporations could move to regions that had no carbon policies. Societies across the world take on the problem and develop a moral backing in order to absorb the increased cost and the sacrifices needed to achieve the targets. In the U.S., this cost will come in the form of continued production tax credits, increased CO_2 costs and increased fossil fuel costs due to increased environmental constraints for drilling and mining.

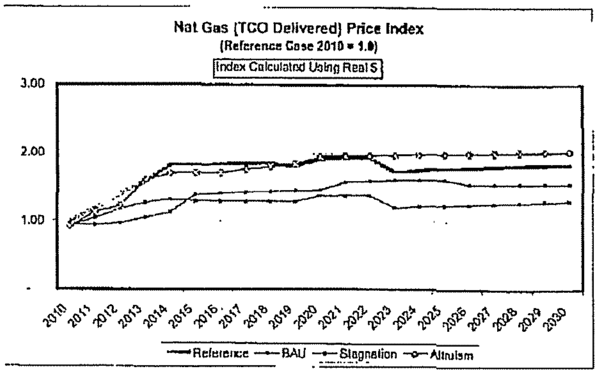
The relationship among commodity prices under the different economic scenarios is shown in **Exhibit 8-3**. Forecasts of particular importance include coal prices, natural gas, CO_2, and on-peak and off-peak power prices. Because commodity price forecasts are considered business sensitive information, the comparisons are made using an index, with the Reference Case 2010 price set as 1.0.

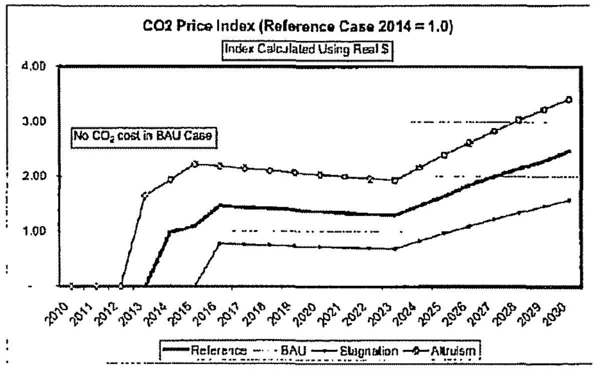
AMERICAN ELECTRIC POWER

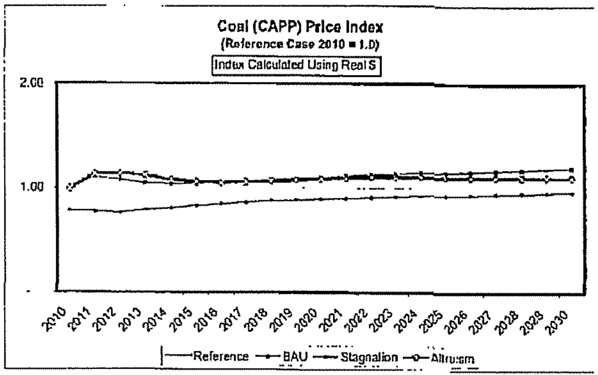
Exhibit 8-3 Commodity Price Forecast by Scenario

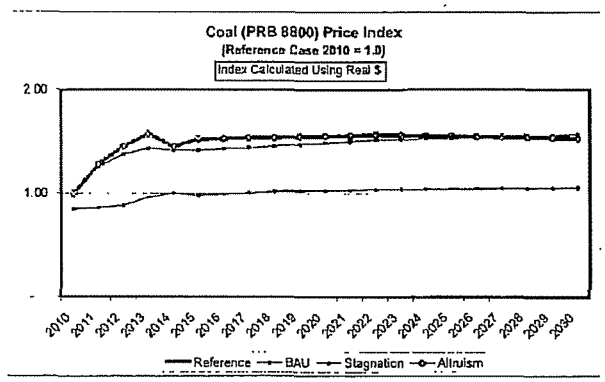












9.0 Resource Portfolio Modeling

9.1 The *Strategist* Model

The *Strategist* optimization model served as the empirical calculation basis from which the AEP-East zonal capacity requirement evaluations were examined and recommendations were made. As will be identified, as part of this iterative process, *Strategist* offers unique portfolios of resource options that can be assessed not only from a discrete, revenue requirement basis, but also for purposes of performing additional risk analysis outside the tool.

As its objective function, *Strategist* determines the regulatory least-cost resource mix for the generation (G) system being assessed.[10] The solution is bounded by user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

Strategist develops a discrete macro (zone-specific) least-cost resource mix for a system by incorporating a variety of expansion planning assumptions including:

- Resource alternative characteristics (e.g., capital cost, construction period, project life).
- Operating parameters (e.g. capacity ratings, heat rates, outage rates, emission effluent rates, unit minimum downturn levels, must-run status, etc.) of existing and new units.
- Unit dispositions (retirement/mothballing).
- Delivered fuel prices.
- Prices of external market energy and capacity as well as SO_2, NO_X, and CO_2 emission allowances.
- Reliability constraints (in this study, minimum reserve margin targets).
- Emission limits and environmental compliance options.

These assumptions, and others, are considered in the development of an integrated plan that best fits the utility system being analyzed. *Strategist* does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only (G)-COS that changes from plan-to-plan, not fixed embedded costs associated with existing generating capacity that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non site-specific) capacity resource modeling would typically not incorporate significant capital spends for transmission interconnection costs.

Specifically, *Strategist* includes and recognizes in its "incremental (again, largely (G)) revenue requirement" output profile:

- Fixed costs of capacity additions, i.e., carrying charges on capacity and associated transmission (based on a weighted average AEP system cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Program costs of DR/EE alternatives

[10] *Strategist* also offers the capability to address incremental transmission ("T") options that may be tied to evaluations of certain generating capacity resource alternatives.

- Variable costs associated with the entire fleet of new and existing generating units (developed using its probabilistic unit dispatch optimization engine). This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs;
- Market revenues from external energy transactions (i.e. Off-System Sales) are netted against these costs under this ratemaking/revenue requirement format.

In order to create a full regulatory cost of service, additional cost were developed to capture the revenue requirement impact from the embedded fixed cost of AEP's existing generation, transmission and distribution systems (i.e. G/T/D costs). These additional G/T/D revenue requirements were added to the incremental revenue requirements developed by *Strategist* to create a full regulatory cost of service.

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from potentially hundreds of thousands of possible resource alternative combinations created by the module's chronological dynamic programming algorithm. On an annual basis, each capacity resource alternative combination that satisfies various user-defined constraints (to be discussed below) is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations and the number of feasible states increases exponentially with the number of resource alternatives being considered.

9.1.1 Modeling Constraints

The model's algorithm has the potential for creating such a vast number of alternative combinations and feasible states; it can become an extremely large computational and data storage problem, if not constrained in some manner. The *Strategist* model includes a number of input variables specifically designed to allow the user to further limit or constrain the size of the problem. There were numerous other known physical and economic issues that needed to be considered and, effectively, "constrained" during the modeling of the long-term capacity needs so as to reduce the problem size within the tool.

- Maintain an AEP-PJM installed capacity (ICAP) minimum reserve margin of roughly 15.5% per year as represented in the east region's "going-in" capacity position (which itself assumed a PJM Installed Reserve Margin (IRM) of 15.5% throughout the 2011/2012 planning year and 15.3% effective 2013/2014 and through the remaining years of the planning period).
- All generation installation costs represent AEP-SEA view of capacity build prices that were predicated upon information from AEP Generation Technology Development.
- Under the terms of the NSR Consent Decree, AEP agreed to annual SO_2 and NO_X emission limits for its fleet of 16 coal-fueled power plants in Indiana, Kentucky, Ohio, Virginia and

West Virginia. These emission limits were met by adjusting the dispatch order of these units during *Strategist's* economic dispatch modeling.

9.2 Resource Options/Characteristics and Screening

9.2.1 Supply-side Technology Screening

There are many variants of available supply and demand-side resource types. It is a practical limitation that not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for each of the major duty cycle "families" (baseload, intermediate, and peaking).

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty cycle family. Rather, they reflect proxies for modeling purposes.

Other factors will be considered that will determine the ultimate technology type (e.g. choices for "peaking" technologies: GE frame machines "E" or "F", GE LMS100 aeroderivative machines, etc.). The full list of screened supply options is included in **Appendix C**.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Strategist* for each designated duty cycle:

- *Peaking capacity* was modeled as blocks of eight, 82 MW GE-7EA Combustion Turbine units (summer rating of 78.5 MW x 8 = 628 MW), available beginning in 2019. Note: No more than one block could be selected per year.
- *Intermediate capacity* was modeled as single natural gas Combined Cycle (2 x 1 GE-7FB with duct firing platform) units, each rated 650 MW (613 MW summer) available beginning in 2019.
- *Baseload capacity* burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions was considered in selecting the solid fuel baseload capacity alternatives. Two solid fuel alternatives were made available to the model:
  - ✓ 526 MW Ultra Supercritical PC unit (summer rating of 520 MW) where the unit is installed with chilled ammonia carbon capture and storage (CCS) technology that would capture 90% of the unit's CO_2 emissions. This option could be added beginning in 2020.
  - ✓ 776 MW Integrated Gasification Combined Cycle (IGCC) "H" Class unit equipped with CCS technology that would reduce 90% of the unit's carbon emissions. This alternative could be added by *Strategist* beginning in 2020 and;

In addition, beginning in the year 2022:

- ✓ *Strategist* could select an 800 MW share of a 1,606 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (771 MW summer)

In order to maintain a balance between peaking, intermediate and baseload capacity resources, only eight Combustion Turbine (CT) units could be added in any year. If the addition of eight CTs was not sufficient to meet reliability requirements in a particular year, the model was required to add either intermediate and/or baseload capacity to meet the reliability targets.

9.2.2 Demand-side Alternative Screening

As described in **Section 7**, eighteen "blocks" of EE programs were available each year to be evaluated in *Strategist* over the 2011-2015 period. There were also a total of twelve 50 MW blocks of DR that could be added (2-3 per year) over the 2011-2015 period. In addition, there were a total of 7 blocks of Integrated Voltage/Var (IVV) control that could be added over the 2012-2018 period. The economics of the DR/EE/IVV blocks were screened in order to minimize the problem size of the full *Strategist* optimization. The DR/EE/IVV blocks were evaluated under all of the economic scenarios described in **Section 8**. The results of this screening analysis showed that 560 MW of EE and 600 MW of DR were selected under all of the economic scenarios. In all economic scenarios, 30 MW to 110 MW of IVV was selected depending on the economic scenario.

9.3 *Strategist* Optimization

9.3.1 Purpose

Strategist should be thought of as a tool used in the development of potentially economically viable resource portfolios. It doesn't produce "the answer;" rather, it produces or suggests many portfolios that have different cost profiles under different pricing scenarios and sensitivities. Portfolios that fare well under all scenarios and sensitivities are considered for further evaluation. The optimum, or least-cost, portfolio under one scenario may not be a low-cost, or even a viable portfolio in other scenarios. Portfolio selection may reflect strategic decisions embraced by AEP leadership, including a commitment to DR/EE, renewable resources and clean coal technology. *Strategist* results, both "optimum" and "suboptimum," serve as a starting point for constructing model portfolios.

For example, if a scenario dictates an unconstrained *Strategist* consistently picks a CT option to the point that such peaking capacity is being added in large quantities, a portfolio that substitutes a 650 MW combined cycle plant for eight, 82 MW CTs might be constructed and tested through *Strategist* to see if the resultant economic answer (i.e., CPW of revenue requirements) is significantly different. Intervening in the algorithm of *Strategist* to insert some additional practical constraints or conform to an AEP strategy yields a solution that is more realistic and not injuriously more expensive. The optimum or least expensive portfolio under a scenario may have practical limitations that *Strategist* does not take into full account.

9.3.2 Strategic Portfolios

Strategic decisions that were considered when constructing the underlying AEP-East resource portfolios include:

- **Renewable Resources:**
  - ✓ On an AEP system-wide basis, to achieve 6% of energy sales from renewable energy sources by 2013, 10% by 2020 and 15% by 2030.
  - ✓ Recognition of potential for a Federal RPS and mandatory state RPS in Ohio, Texas, Michigan, and West Virginia and voluntary RPS in Virginia.
- **Assumptions on "early mover" commitment to these GHG and renewable strategies**
  - ✓ Limit exposure to scarce resource pricing.
  - ✓ Take advantage of current tax credit for renewable generation.
  - ✓ Reduce exposure to potential GHG legislation, as initial mitigation requirements unfold.
  - ✓ Plan to be in concert with other CO_2/GHG reduction options (offsets, allowances, etc.).
- **Energy efficiency:** Consideration of increased levels of cost-effective DR/EE over previous resource planning cycles reflects additional state mandates, stakeholder desires for such measures, as well as regulator willingness in the form of revenue recovery certainty.

As will be described, additional sensitivities were then contemplated to determine the effects of the optimum portfolios, as well as to build additional portfolios. The build plans that were suggested by *Strategist* under the various scenarios and sensitivities are described in the following sections.

9.4 Optimum Build Portfolios for Four Economic Scenarios

9.4.1 Optimal Portfolio Results by Scenario

Given the four fundamental pricing scenarios developed by AEP-FA from **Section 8.3**, as well as the modeling constraints and certain planning commitments, *Strategist* modeling was used to develop the incremental portfolios identified in **Exhibit 9-1**:

Exhibit 9-1: Model Optimized Portfolios under Various Power Pricing Scenarios

	Business As Usual Case Optimization	Stagnation Case Optimization	Reference Case Optimization	Altruism Case Optimization
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019	8 - 82 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs, 1 - 650 MW CC
2020				
2021	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2022				
2023				
2024		8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2025				
2026	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2027				
2028				
2029	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs	8 - 82 MW CTs
2030				
Total East System Cost				
2010-2035 CPW ($M)	119,139,548	123,097,624	134,133,179	146,370,495
2010 - 2030 Levelized ($/MWh)	82.85	88.35	95.48	103.68
Number of Units Added				
CT	32	40	40	40
CC	1	1	1	1
PC	0	0	0	0
IGCC	0	0	0	0
Nuclear	0	0	0	0
Total Capacity (MW)	3,274	3,930	3,930	3,930
Total Optimized DR/EE/IVV (MW Reduced)	1,185	1,265	1,265	1,265

Source: AEP Resource Planning

Notes:

1) *Because Renewable assets and a base level of incremental DR/EE/IVV are included in all portfolios, Strategist did not represent them as incremental resources within these comparative portfolio views.*
2) *The total capacity of the supply-side additions assumes that the **540 MW Dresden CC** unit would become operational in April 2013.*
3) *The IRP planning horizon extends to 2020 as represented by the horizontal line. For modeling purposes Strategist constructs portfolios through 2030.*

9.4.2 Observations: 2019 Combined-cycle Addition

As shown in **Exhibit 9-1**, all pricing scenarios added a CC unit in 2019. The CC addition is made because of the constraint imposed on the model that allows only a single block of 8 CTs to be added in any one year. Had the model been allowed to add as many CT blocks as economic, an additional block of 8 CTs would have been added in 2019 instead of the CC under all pricing scenarios.

9.4.3 Additional Portfolio Evaluation

As an extension of the optimal portfolios created under the four pricing scenarios, several additional portfolios were tested, or developed around defined objectives. These portfolios were created with the goal of examining the economics of portfolios created under factors and influences other than commodity prices. These portfolios can be defined as follows:

- Retirement Transformation Plan – Accelerate All "Fully" Exposed Unit Retirements to 1/2016 and Retire All "Partially" Exposed Units between 1/2016 and 1/2020
- No CCS Retrofits on Existing Units
- Alternative Resource Plan - Enhanced Renewables and DR/EE/IVV + Best "Contrary" Nuclear Plan
- Green Plan - Alternative Resources Plan + Retirement Transformation Plan

Exhibit 9-2 provides a summary of these portfolios under Reference Case conditions.

Exhibit 9-2: Portfolio Summary

	Retirement Transformation Plan	No CCS Retrofits on Existing Units	Alternative Resource Plan	Green Plan
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016	8 - 165 MW CTs, 1 - 650 MW CC			8 - 82 MW CTs
2017	8 - 165 MW CTs, 2 - 650 MW CC			
2018			8 - 165 MW CTs, 1 - 650 MW CC	8 - 165 MW CTs, 2 - 650 MW CC
2019	8 - 165 MW CTs, 2 - 650 MW CC	8 - 165 MW CTs, 1 - 650 MW CC	8 - 82 MW CTs	8 - 165 MW CTs, 2 - 650 MW CC
2020				
2021	8 - 82 MW CTs		1-800 MW Nuke	1-800 MW Nuke
2022				
2023				
2024		8 - 82 MW CTs		
2025	8 - 82 MW CTs			
2026		8 - 82 MW CTs	8 - 82 MW CTs	
2027				8 - 82 MW CTs
2028	8 - 82 MW CTs			
2029		8 - 82 MW CTs	8 - 82 MW CTs	
2030				8 - 82 MW CTs
Total East System Cost Under Reference Price Scenario				
2010-2035 CPW ($M)	136,035,511	136,638,030	136,115,947	137,196,444
2010 - 2030 Levelized ($/MWh)	9.72	9.73	9.72	9.83
Number of Units Added				
CT	48	32	32	40
CC	5	1	1	4
Nuclear	0	0	1	1
Total Capacity (MW)	7,186	3,274	4,074	6,680
Total Optimized DSM (MW Reduced)	1,265	1,265	1,703	1,703

Source: AEP Resource Planning

9.4.3.1 "Retirement Transformation" Plan

The objective behind examining this portfolio was to determine the increased cost of a portfolio that accelerated the retirement of all "Fully Exposed" units and the retirement all of the "Partially Exposed" units that were scheduled to receive emission retrofits. In all other cases, several of the Full

Exposed units had retirement dates that occurred after 2016. In the Retirement Transformation Plan, those retirements that were profiled to occur from 2016 through 2019 as part of the Unit Disposition analysis described in Section 3 were accelerated to January 2016. In addition, the Partially Exposed units were assumed to be retired on the date they were originally profiled as part of the same disposition process to receive emission retrofits.

9.4.3.2 "No CCS Retrofits" Plan

In all other pricing scenarios but Business As Usual, approximately 3,700 MW of existing AEP-East solid-fuel units were assumed to be retrofitted with CCS technology. When CCS retrofits were installed, CO_2 "Bonus Allowances" were awarded to AEP to offset the cost of installing the CCS retrofits.[11] In this portfolio, the objective was to determine the increased cost of CO_2 emission exposure by not performing the CCS retrofits and obtaining the Bonus Allowances. Instead, AEP's entire solid-fuel generating fleet would be subject to the assumed CO_2 emissions cost under each pricing scenario.

9.4.3.3 "Alternative Resource" Plan

The Alternative Resource Plan was created by combining:

- Increasing the levels of renewable energy resources and DR/EE/IVV added to the system by a relative magnitude of fifty percent, and;
- The "Best" Contrary Nuclear Plan, which was the best "sub-optimal" plan established by *Strategist* that included a nuclear baseload resource..

The renewable energy targets set for this scenario require that 6% of system-wide energy sales be met with renewable energy resources by 2013, 15 percent (versus 10 percent) by 2020 and 22.5 percent (versus 15 percent) by 2030. The timing of the nuclear unit addition in the Contrary Nuclear Plan was established during the initial optimization analysis as the "optimal" point in time in the early 2020s to add Nuclear baseload capacity.

9.4.3.4 "Green" Plan

The Green Plan was created by combining the Retirement Transformation Plan and the Alternative Resource Plan. The purpose of creating the Green Plan was to test the economics of a portfolio with very low emissions profiles by introducing the accelerated retirement of solid fuel units, increased levels of renewable energy and DR/EE/IVV and the addition of a low emitting nuclear unit.

A summary of the Optimal Portfolio and Additional Portfolio plan's costs over the full (2010-2035) extended planning horizon, and under the various pricing scenarios is shown in **Exhibit 9-3**.

[11] "Bonus Allowances" designed to incentivize commercial development of CCS technology have been incorporated as part of the House-approved Waxman-Markey Bill as well as comparable Senate legislation currently under discussion.

Exhibit 9-3: Optimized Plan Results (2010-2035) Under Various Pricing Scenarios

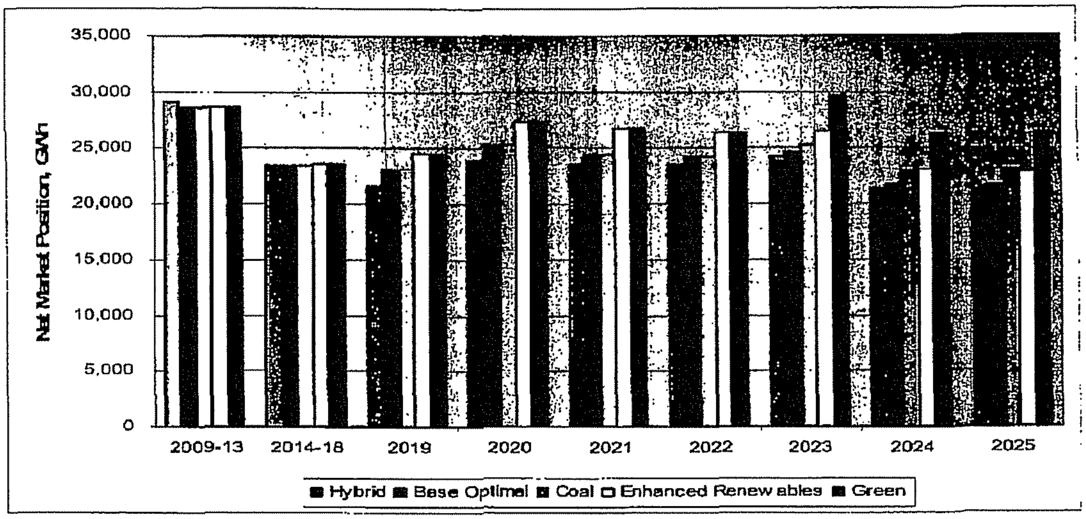
AEP East 2010-2035 CPW ($000)	NO Carbon Legislation / Regulation World	(Ultimate) Carbon Legislation		
Pricing Scenario	"BAU"-(Alt) LOW Proxy- (No CCS)	"Stagnation" - LOW Proxy- (with CCS*)	"Reference" -BASE Proxy- (with CCS*)	"Altruism" -HIGH Proxy- (with CCS*)
'BAU' (No CO2) (LOW Price w/o CO2)Scenario Optimal Plan	$119,139,548	$123,608,730	$136,014,837	$148,670,225
'Stagnation' (LOW Price w/ CO2) Scenario Optimal Plan	$126,137,376	$123,097,624	$134,133,179	$145,385,453
'REFERENCE' (BASE Price) Scenario Optimal Plan	$126,137,376	$123,097,624	$134,133,179	$145,385,453
'Altruism' (HIGH Price) Scenario Optimal Plan	$126,133,852	$123,097,462	$134,123,709	$145,379,495
Retirement Transformation Plan...Reflect RETIREMENT of all 'Partially Exposed' Units; 2016-2020		$124,624,453	$136,035,511	$146,132,185
No CCS Retrofits (in lieu of assumed (subsidized) ~5,500 MW by 2020 in 'BASE')		$124,256,115	$136,638,930	$149,257,679
"Alternative Resources Plan"... Best 'HIGH' Renewable / "Efficiency" + Best 'Contrary' Nuc		126,602,394	136,115,947	146,668,529
"Green Plan"... 'Alternative Resources' Plan (above) + Retire All 'Partially-Exposed' Units by 1/2016 + Retire All 'Partially-Exposed' Units by 1/2020		$127,568,854	137,196,444	$146,776,618

Source: AEP Resource Planning

9.4.4 Market Energy Position of the AEP East Zone

The AEP-East fleet is projected to undergo a change in its operational mix particularly beginning in the year 2015 as older coal units retire. This leaves a smaller number of units available to serve a baseload function. This could expose the AEP LSEs to market prices and would cause them to become, in effect, "price takers" from the market. The probability of this occurring in a potential portfolio is reduced when AEP maintains a minimum net market (energy) position of approximately 10% of its annual energy requirements, or 12,000 GWH. **Exhibit 9-4** shows that each of the portfolios evaluated meet this criteria.

Exhibit 9-4: Annual Energy Position of Evaluated Portfolios



Source: AEP Resource Planning

9.4.5 Portfolio Views Selected for Additional Risk Analysis

The following summarizes the six portfolio views as set forth by the discrete AEP East capacity resource modeling performed using *Strategist* that were analyzed further in the Utility Risk Simulation Analysis (URSA) model described in **Section 10.**

- Reference Pricing Case Optimal Plan (Base Plan)
- Business As Usual Pricing Case Optimal Plan (No CO_2 Plan)
- Retirement Transformation Plan
- No CCS on Existing Units Plan
- Alternate Resources Plan
- "Green Plan"

These resource portfolio options created in *Strategist* and their revenue requirements offer modeled economic results based on specific, discrete "point estimates" of the variables that could affect these economics. These portfolios were evaluated over a *distributed range* of certain key variables in URSA, which provided a probability-weighted solution that offers additional insight surrounding relative cost/price risk.

10.0 Risk Analysis

The six portfolios identified in **Section 9** that were selected using *Strategist* and the Hybrid plan were subjected to rigorous "stress testing" to ensure that none would have outcomes that would be deleterious under a probabilistic array of input variables.

10.1 The URSA Model

Developed internally by AEP Market Risk Oversight, the Utility Risk Simulation Analysis (URSA) model uses Monte Carlo simulation of the AEP East Zone with 1,399 possible futures for certain input variables. The results take the form of a distribution of possible revenue requirement outcomes for each plan. The input variables or risk factors considered by URSA within this IRP analysis were:

- Eastern and Western coal prices,
- natural gas prices,
- uranium prices,
- power prices,
- emissions allowance prices,
- full requirements loads.
- steam and combustion units forced out.

These variables were correlated based on historical data.

For each plan, the difference between its mean and its 95th percentile was identified as Revenue Requirement at Risk (RRaR). This represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of 5.0 percent.

Exhibit 10-1 illustrates for one plan, the "Hybrid Plan," the average levels of some key risk factors, both overall and in the simulated outcomes whose Cumulative Present Value (CPV) revenue requirement is roughly equal to or exceeds the upper bound of Revenue Requirement at Risk. Note that these CPV's are consistent with the CPW values calculated using the *Strategist* tool. The table is specific to the Hybrid Plan, but the numbers would be very similar under the other plans. (The particular alternative futures producing the highest levels are not necessarily the same between different plans.)

Exhibit 10-1: Key Risk Factors – Weighted Means for 2010

	Simulated Outcomes - Hybrid Plan			
	All Outcomes	RRaR-Exceeding Outcomes		
Variable	Mean	Mean	Difference	% Diff
AEP Internal Onpeak Load	16,033	16,024	(8.78)	-0.05%
AEP Onpeak Power Spot	75.47	82.47	7.00	9.28%
CO2 Allowance Spot	25.04	58.24	33.20	132.59%
NYM Coal Spot	61.60	65.49	3.89	6.31%
Henry Hub Gas Spot	7.94	9.07	1.13	14.23%
Uranium Spot	0.81	0.82	0.01	1.23%
Steam Units Forced Out	1,668	1,670	1.74	0.10%
Combustion Units Forced Out	509.46	510.06	0.60	0.12%

Source: AEP Market Risk Oversight

The price of CO_2 allowance, spot gas, and on-peak power prices is greater among the RRaR-exceeding outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between that "tail" and mean outcomes are 132.59%, 14.23%, and 9.28%, which is significantly greater than the relative difference of other risk factors.

It might be assumed that the very worst possible futures would be characterized by high fuel and allowance prices and low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with high fuel prices would essentially always have high power prices. Likewise the risk factor analysis implies an inverse correlation between NO_X allowance prices and some of the other risk factors that determine the tail cases, so that in these tail cases, the average NO_X allowance price is actually less than the average across all possible futures.

10.2 Installed Capital Cost Risk Assessment

In order to further scrutinize the six plans under the 1399 possible futures, the impacts of Installed Capital Cost Risk on the URSA results were examined. A six-point capital cost distribution for each of the seven plans was created. (See **Exhibit 10-2** for its basis.) In creating the distribution for each plan, the installed capital costs of all types of generating capacity were assumed to be perfectly correlated with each other. The fixed representation of installed capital costs in URSA was removed from each URSA output distribution and the resulting distributions were convolved with the installed capital cost distributions.

Exhibit 10-2: Basis of Installed Capital Cost Distributions

Probability of occurrence, **Percent Capital Cost Variance**:	5%	19%	33%	23.67%	14.33%	5%
Solid-fuel Units	-15%	-7.5%	Base	13.33%	27%	40%
Gas-fuel Units	-10%	-5%	Base	6.67%	13.33%	20%
Nuclear Units	-15%	-7.5%	Base	16.67%	33%	50%

Source: AEP Resource Planning

10.3 Results Including Installed Capital Cost Risk

Exhibit 10-3 summarizes the Installed Capital Cost Risk-adjusted results for all six AEP-East plans.

Exhibit 10-3: Risk -Adjusted CPW 2010-2035 Revenue Requirement ($ Millions)

PLAN	50th Percentile	95th Percentile	RRaR
No CO2	119,190	124,965	5,775
Base Case	134,174	163,009	28,835
Accel Coal Ret	136,092	162,162	26,070
No CCS	136,701	168,324	31,623
Alt Resc	136,370	162,955	26,585
Green	137,424	161,280	23,856

Source: AEP Resource Planning

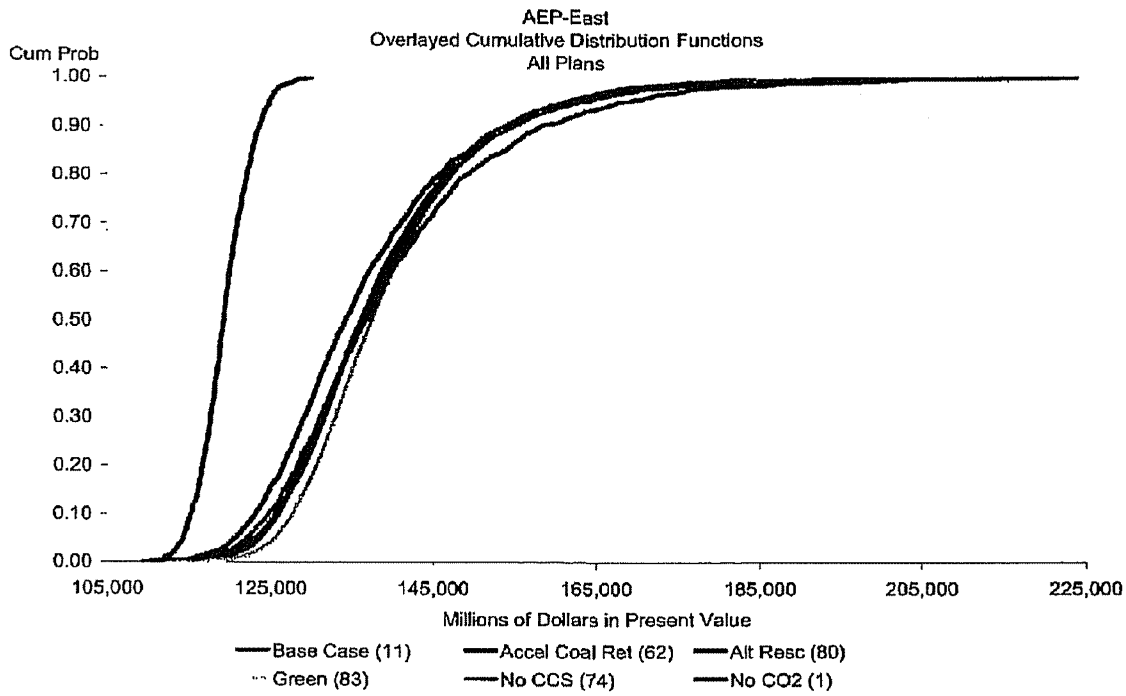
Exhibit 10-3 shows reasonably consistent results across all plans modeled. These comparative results also suggest that, given the fuel/generation diversity of the capacity resource options introduced into the analysis, the relative economic exposure would appear to be small irrespective of the plan selected.

The three lowest-cost plans at the 50th percentile are the No CO_2, Base Case, and Accelerated Coal Retirements. However, the lowest cost plans at the Revenue Requirement at Risk are the No CO_2, Green, and Accelerated Coal Retirements. While the lowest cost plan at the 95th percentile is the No CO_2 plan, keep in mind that the No CO_2 plan is not directly comparable to the other plans in that CO_2 costs are excluded. The plan was included to point out the expected cost of CO_2 legislation on ratepayers. As the exhibit shows, this impact ranges from approximately $15 billion to $40 billion on a net present value basis.

RRaR measures the risk relative to the 50th percentile, or expected, result of a plan. The plan with the least RRaR is not necessarily preferred for risk avoidance. Instead, low values of required revenue at extreme percentiles, such as the 95th, are preferred.

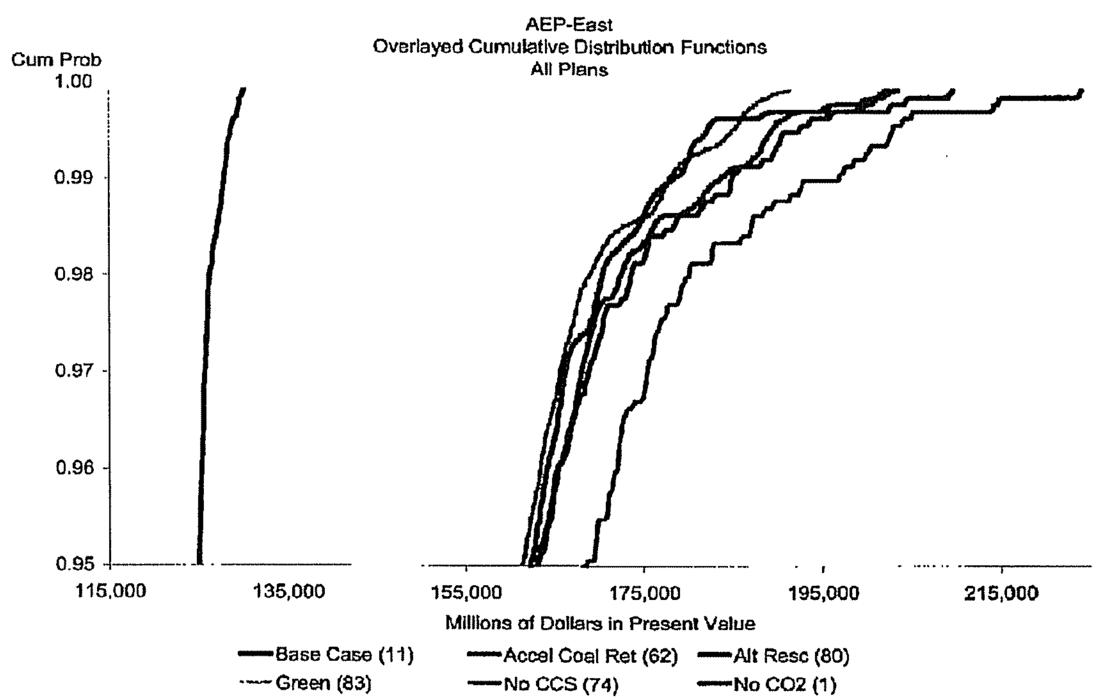
The estimated distributions of revenue required under the seven plans are rather similar. **Exhibits 10-4** and **10-5** show the superimposed graphs of all six distribution functions. **Exhibit 10-4** shows entire distributions; **Exhibit 10-5** shows only the region at or above the 95th percentile.

Exhibit 10-4: Distribution Function for All Portfolios



Source: AEP Resource Planning

Exhibit 10-5: Distribution Function for All Portfolios at > 95% Probability



Source: AEP Resource Planning

10.4 Conclusion from Risk Modeling

The Base Plan had the lowest cost at the 50% probability level but had the second highest cost at the 95% probability level (the Green Plan had the lowest). While the Green Plan has a lower RRaR at 95% probability, it is significantly more expensive at the 50% probability level. The risk mitigation benefits of the Green Plan are tied to potential extremes in CO_2 pricing, as indicated from the discrete modeling results from *Strategist* where the Green Plan is the preferred plan under the Altruism pricing, but not under other pricing scenarios.

The results indicate that AEP-East should continue to aggressively pursue addition of renewables and DR/EE where regulatory support is provided, and to remain open to the possibility of the addition of nuclear capacity. Recent experience has shown that state regulatory bodies are under pressure from ratepayers to keep rates low, especially during the current economic climate, and as a result they may be reluctant to support efforts to increase energy diversity that are not required by a state or federal mandate if those initiatives cause near-term rates to increase. This may limit the levels of renewables and DR/EE that could potentially be employed in the resource mix. The levels used in the Hybrid Plan, while somewhat aggressive, are believed to be realistically achievable.

The Hybrid Plan, developed using a more recent, lower load forecast, does not show the need for baseload capacity even after all proposed coal unit retirements occur, which would suggest that, at this point in time consideration of a nuclear addition is not warranted. The URSA results show that the planned additions of CCS equipment on existing facilities, which is a component of the Hybrid Plan, produces a lower cost plan than excluding CCS. The addition of a full scale CCS equipment retrofit will be dependent first on the successful outcome of the Mountaineer pilot project and then on the federal incentives which are expected to be necessary to keep such retrofits at a reasonable cost to customers.

11.0 Findings and Recommendations

11.1 Development of the "Hybrid" Plan

Using the intelligence gained from the *Strategist* runs for various pricing and sensitivity scenarios, an AEP-East "Hybrid" plan was created that primarily focused on the following:

- While the IRP process was taking place, the Economic Forecasting group prepared a revised load forecast in April, 2010. The revised forecast reflected a downturn in economic conditions over AEP's East service area and in turn, a reduction in AEP East's peak and energy requirements compared to the forecast used in the IRP process. The "April" forecast showed a reduction in energy requirements of 4% - 8% and a 5% - 10% reduction in peak demand over the planning period compared to the load forecast used in the IRP process. In recognition of the April forecast's lower peak loads, the Hybrid Plan deferred the amount of capacity that had been added in the various IRP optimization runs.
- During the course of the 2010 IRP analysis, it became apparent that reducing the size of AEP's significant carbon footprint would be necessary over the long-term due to the emerging likelihood of some level of CO_2 emission limits in the future. Based on the analysis performed within the No CCS Retrofit view, CCS retrofits were introduced into the AEP-East plan so as to accelerate this further migration to a reduced CO_2 position.
- Due to the retirement of certain units that provide black start capability, the addition of quick-start CT capacity was accelerated to replace this function in certain operating areas.

Based on the array of discrete results from varying pricing scenarios and strategic portfolios, and the risk analysis described in **Section 10**, the Reference Case Optimal Portfolio was determined to be a reasonable basis for the development of the final AEP-East Hybrid Plan shown in **Exhibit 11-1**.

As stated above, during the development of the Hybrid Plan the timing and number of units added in the Reference Case Optimal Plan was adjusted to reflect the reduction in peak loads found in the April 2010 revised load forecast. In addition, the CCS retrofits assumed in the majority of the optimization runs were included in the Hybrid Plan. The reduction in peaking requirements with the April load forecast allowed the number of peaking resources to be reduced from 28 in the Reference Case to 16 in the Hybrid Plan, however an intermediate resource was added in place of eight of these CT's to diversify the energy mix.

The Hybrid Plan identifies thermal capacity additions by duty cycle. With the exception of committed capacity additions, such as Dresden, or enhancements to existing resources, such as the Cook uprate, *the thermal capacity identified is intended to represent "blocks" of capacity that fit that duty cycle and do not imply a specific solution or configuration.*

The selection of the Hybrid Plan reflects management's commitment to a diverse portfolio including renewable energy alternatives and demand reduction/energy efficiency. This resource portfolio compares favorably to other portfolios when subjected to robust statistical analysis, providing low reasonable life-cycle cost on average, and relatively low risk to its customers. Other benefits include:

- Keeping coal as a viable fuel in a carbon-constrained world through the use of CCS technology. AEP service territory encompasses some of the most prolific coal producing regions in the nation. AEP's steeped history and core competency surrounding coal-based generation would also naturally support such a commitment.
- With mandatory Renewable Portfolio Standards in force in Michigan, West Virginia, and Ohio, and a voluntary standard in Virginia, securing wind power ensures that AEP will be well positioned to achieve those standards.
- Increased DR/EE, consistent with state objectives, assuming customer acceptance and full and contemporaneous rate recovery, could offer an effective means to reduce demand, energy usage, and as a result, our carbon footprint.
- Ability to meet emission caps set forth in the NSR case Stipulated Agreement.

Exhibits 11-1 through **11-3** offer a summary of the Hybrid plan and the resulting AEP-East generating fleet from capacity and energy mix standpoint. From an environmental stewardship perspective, note that **Exhibit 11-2** shows the respective AEP-East fleet continues to migrate to a lower carbon emitting portfolio. The most significant take-away, as shown in **Exhibit 11-3,** would be that, in 2020 and 2030, the plan relies more heavily on renewable resources and nuclear and less on baseload coal to meet its needs.

Exhibit 11-1: Hybrid Plan

"Hybrid" Portfolio:
Reflective of April-10 Load Forecast [(a)]

AEP-East

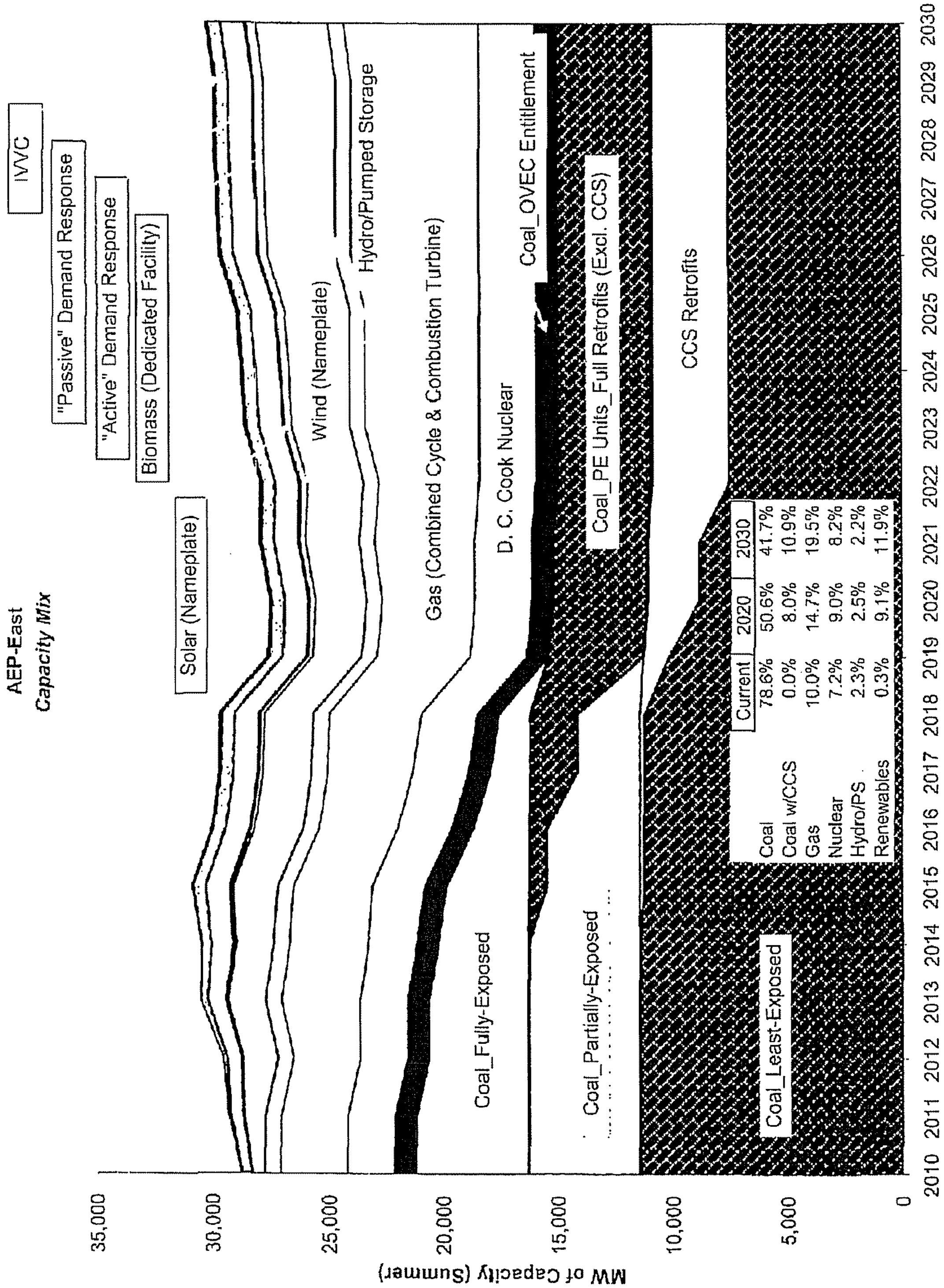
Period	Pln Yr	(b) Capacity (Retire)	CCS Retrofit Unit	CCS Retrofit Capac	CCS Retrofit Derate	Efficiency: Dem (c) Response ("Active"DR)	Efficiency: Energy (a) Efficiency ("Passive"DR)	Efficiency: Infrastruc. (e.g. IVVC)	Renewable (Nameplate) (d): Wind	Renewable (Nameplate) (d): (e) Biom	Renewable (Nameplate) (d): Solar	Thermal Resources (summer rating)	Oper Co. Assigned		PJM-CLR Capacity Position (above PJM IRM min) (MW)
(10-Year) Planning Period	2010	(440)					16		451		10		⇩	(f)	1,240
	2011					100	90		101	44	10			(g)	1,292
	2012	(560)				100	93		100		11			(h)	1,113
	2013					150	102		100	25	10	(Dresden) CC-540	APCo		2,038
	2014	(395)				150	112	19	300	25	26	Cook2 (Ph1)-45	I&M		2,720
	2015	(925)	MT	235	(58)	100	89	31	400		27	Cook1&2 (Ph1&2)-168	I&M		2,188
	2016	(1,175)					67	17	250	(44)	26	Cook1 (Ph2)-68	I&M		1,934
	2017	(675)					59	16	150		26	Cook2 (Ph3)-68 NG Peaking-314	I&M APCo	(i)	1,968
	2018	(400)					48	17	50	100	26	Cook1 (Ph3)-68 NG Peaking-314	I&M APCo/KPCo	(j)	1,856
	2019	(1,373)	MT	1,065	(137)		88		100		28				343
	2020		GV1	1,300	(195)		104		150		27				399
Study Period	2021						72		100	50	29	NG Peaking-314	APCo/KPCo	(k)	388
	2022		AM3	1,300	(195)		51		100		45				359
	2023						35		200			NG Intermediate-611	APCo		420
	2024						21		150	100	45				403
	2025						16		150						232
	2026						5		150		20	NG Intermediate-611	APCo		677
	2027						1		150	50					523
	2028								100		25				403
	2029														204
	2030										31	NG Peaking-314	APCo		304
				3,900				"Nameplate"	3,252	350	420				
	Cumul.	(5,943)			(585)	600	1,069	100	423	50	160	3,435			

2010-2030
Net Addition
(692)

(a) *Underlying Peak Demand as well as "Passive" (Energy Efficiency) Demand Reduction levels are per AEP-Economic Forecasting "April '10" **Forecast** (Note: includes mandated EE requirements in OH, IN, MI)*
(b) Reflects PJM planning year that capacity is de-committed in PJM-FRR
(c) "Active" DR (i.e. demand response curtailment programs/tariffs) only
(d) 13% of wind nameplate and 38% of solar nameplate can be "counted" as PJM capacity (per *initial* PJM criteria)
... Assumes 'full-year' energy impact (i.e. *in-service* by 12/31 of Year -1)
(e) Only 25 MW '2013' and '2014' biomass represents incremental capacity via a dedicated biomass facility (assumed AEP-Ohio PPA)...
... *balance represents* 'equivalent' biomass-sourced energy via co-firing.... through, initially, *existing* AEP-Ohio units
(f) "2010" wind: Fowler Ridge I, II & II (350 MW: AP, I&M, CSP, OP); Grand Ridge I & III (100.5 MW: AP)... "2010" solar: Wyandotte (10MW: CSP, OPCo)
(g) "2011" wind: Beech Ridge (100.5 MW: AP) only... i.e., assumes Lee-Dekalb (100 MW: KP) eliminated as KPSC denied recovery and, as per contract, it may then be voided
(h) "2012" wind: Represents 'Unidentified' 100-MW wind designated to AEP-Ohio companies to be in-keeping w/ requirements of S.B. 221
(i) Assumes advanced four-years (from 2021) to provide Black-Start requirements @ TC area
(j) " " three-years (from 2024) to provide Black-Start requirements @ KM area
(k) " " three-years (from 2021) to provide Black-Start requirements @ SP area

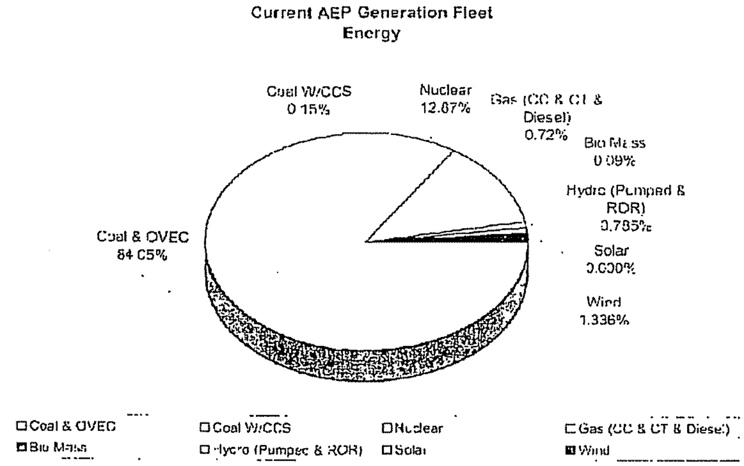
Source: AEP Resource Planning

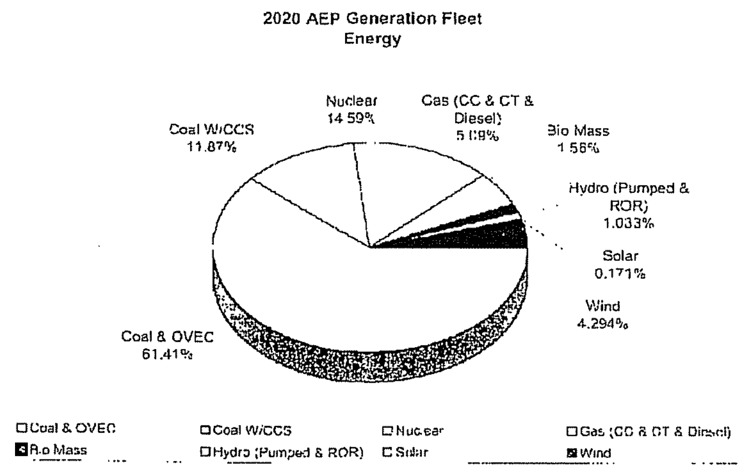
Exhibit 11-2: AEP-East Generation Capacity

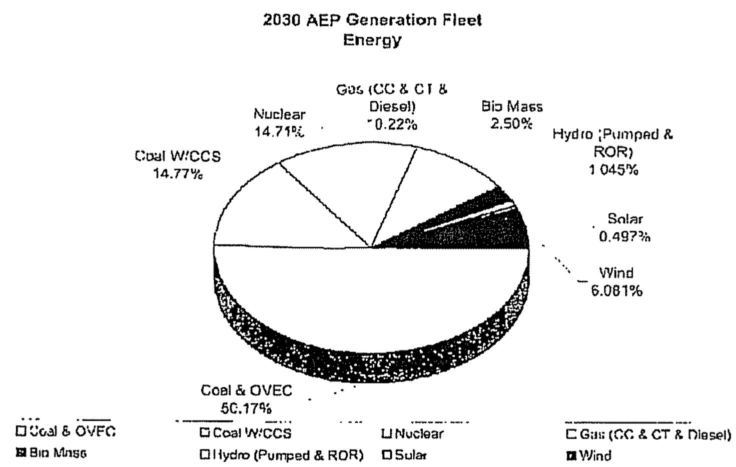


Source: AEP Resource Planning

Exhibit 11-3: Change in Energy Mix with Hybrid Plan Current vs. 2020 and 2030







Source: AEP Resource Planning

11.2 Comparison to 2009 IRP:

The 2009 IRP for AEP-East recommended a slightly different build profile than the current 2010 IRP. The most notable difference between the two plans is that the fleet capacity reductions associated with retiring older coal fired units now concludes in 2019 versus 2023 in the 2009 Plan. Also, Muskingum River 5 is expected to retire in 2015 rather than be retrofitted with an FGD system. This increases the fossil capacity to be removed from service during the next decade. Total new thermal capacity remains unchanged, although the 2009 Plan included a 628 MW peaking facility in 2018 which has been replaced in the 2010 Plan with two 314 MW peaking facilities, one in 2017 and one in 2018. These facilities are required primarily for system restoration, not peaking capacity. Renewable generation sources are generally consistent with the 2009 Plan, however new DSM has increased. This 2010 Plan also introduces Volt/Var Control technology to reduce consumption. A summary of the plan differences is presented in **Exhibit 11-4**.

Exhibit 11-4: Comparison of 2010 IRP to 2009 IRP

All Units in MW	*Planned Resource Reductions*		*Planned Resource Additions*					
			DSM	RENEWABLE				THERMAL
	Unit Retirements (summer-rating)	Environmental Retrofits	*New* Demand Reduction *(Cumul. Contribution)*	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate / New Facility	IVVC	Peaking/ Intermediate/ Baseload
2009 Plan			1.073	118	2 451	103	0	*1,585*
2010 Plan			1,468	225	2.152	150	100	*1,585*
Difference			395	107		47	100	*0*

Source: AEP Resource Planning

12.0 AEP-East Plan Implementation & Conclusions

Once the recommended overall AEP-East resource plan was selected, it was next evaluated from the perspective of its implementation across the region's five member companies. This process involved consideration of:

- Specific operating company resource assignment/allocations based on relative capacity positions; and
- Attendant capacity settlement ("Pool") effects.

12.1 AEP-East—Overview of Potential Resource Assignment by Operating Company

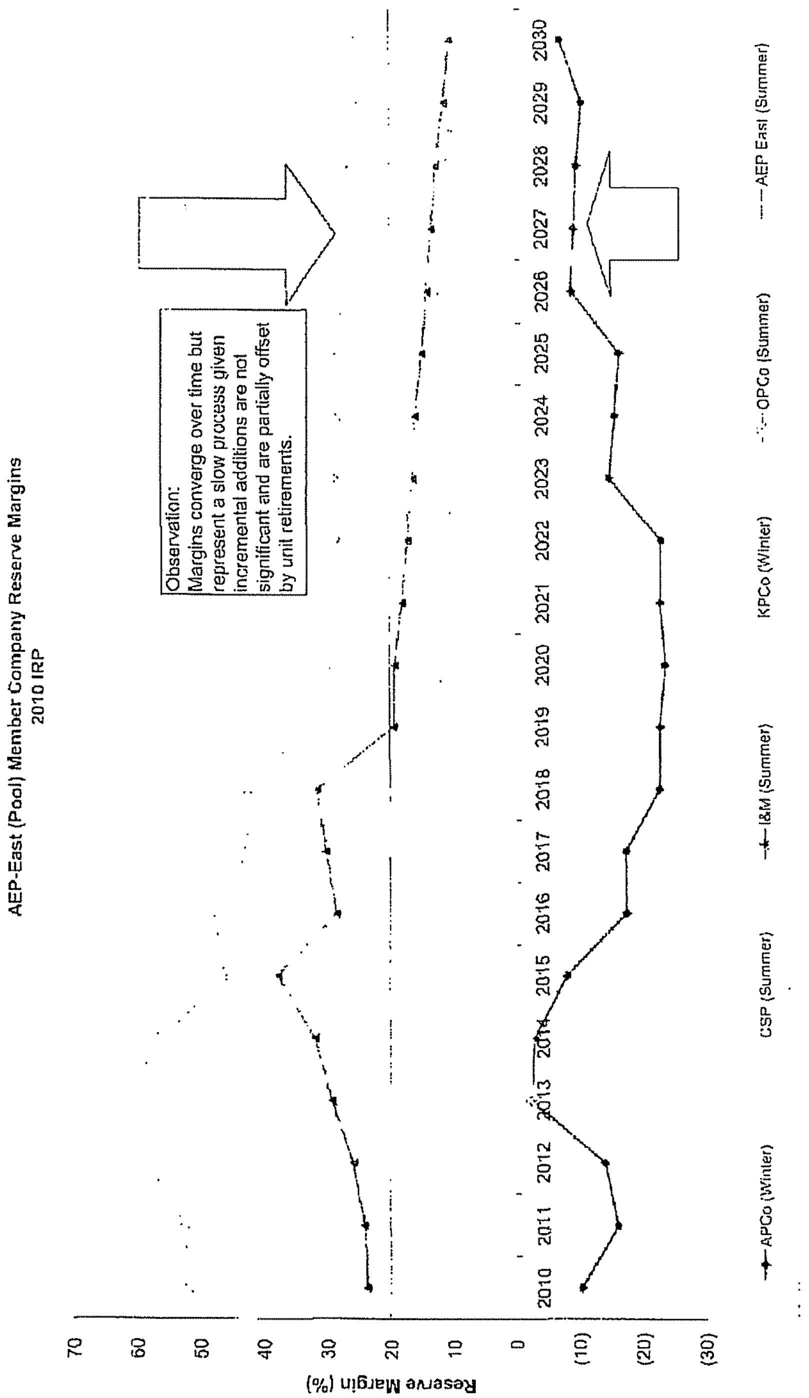
As described throughout this report, the recommended resource plan for AEP's Eastern (PJM) zone was formulated on a region-wide view, recognizing that AEP plans and operates its eastern fleet on an integrated basis, as outlined in the AEP Interconnection ("Pool") Agreement. As specified in the Pool Agreement, each Member Company (APCo, CSP, I&M, KPCo & OPCo) is required to provide an equitable contribution to the incremental capacity resource requirements of AEP-East. This contribution has been historically based on its relative percentage surplus/deficit reserve margin of each company.

Exhibit 12-1 identifies the resulting Member Company Reserve Margins over the next 20 years. As reflected in the chart, the result of this ownership regiment serves to:

- Reduce the absolute capacity deficiency for each Member Company
- Cause the reserve margins of all Member Companies to begin to converge over the 10-year IRP period.

Also, **Appendix J** identifies the Member Company timing and type of new capacity–CT, D (Dresden) CC, Biomass, Wind, – represented in the recommended ("Hybrid") AEP-East capacity resource plan.

Exhibit 12-1: Projected AEP-East Reserve Margin, By Company and System for IRP Period



Source: AEP Resource Planning

12.2 AEP-East "Pool" Impacts

Under the AEP Pool Agreement, capacity cost sharing is determined by each Member Company assuming its Member Primary Capacity Reservation share of the overall (AEP-East zone) System Primary Capacity (calculated by multiplying each Member Company's respective Member Load Ratio {MLR} by the total System Primary Capacity). Consequently, as new capacity is added or removed, all Member Companies' Capacity Settlement payments or receipts are changed.

Exhibit 12-2 summarizes the projected incremental System Pool/Capacity Settlement impacts to the AEP-East zone Member Companies assumed in this recommended 2010 plan. While the largest portion of the incremental capacity resource ownership obligation for new capacity would be borne by APCo, the incremental annual capacity pool "credits" APCo would be, cumulatively, $449 million by the end of 2020

Exhibit 12-2: Incremental Capacity Settlement Impacts of the IRP

Capacity Settlement Benefits/(Costs) ($in Millions) - IRP Change											
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
APCo	-	65	6	92	78	72	(6)	7	(11)	74	73
CSP	-	(14)	(30)	(29)	(32)	10	58	62	104	177	208
I&M	-	(21)	(25)	(33)	(17)	51	21	44	69	21	22
KPCo	-	3	5	4	9	22	34	37	77	39	42
OPCo	-	(33)	45	(34)	(36)	(155)	(107)	(151)	(239)	(310)	(345)
Total	-	0	0	0	0	0	0	0	0	0	0

Source: AEP Financial Forecasting

12.3 New Capacity Lead Times

While the resource plan described in this report covers an extended time period, the only implementation commitments for which a firm consensus must be drawn at this time are those affecting resources that are timed to enter service roughly "one lead-time" into the future. New generation lead time naturally varies depending upon the resource type being contemplated. Depending on siting, land acquisition, permitting, design, engineering, and construction timetables–and whether certain elements (e.g., land or permitting) are already in-place–such lead-times may vary as shown in **Exhibit 12-3**:

Exhibit 12-3: New Capacity Lead Times

	Approximate Lead Time (years)	
Technology	Permitting, license, design	Construction
Simple Cycle	1	1.5
Combined Cycle	1.5 to 2	2
Solid Fuels	2 to 4	4
Nuclear	4	5
Solar PV (e.g., 10 MW Juwi solar)	0.5 to 1	1
Wind Farm	1 to 2	1
Biomass Co-fire	0.5 to 1	0.5

Source: AEP Resource Planning

12.4 AEP-East Implementation Status

1) **Wind Contracts** (by 12/31/2010): Contracts have been signed for wind purchases for a total of 726 MW (nameplate) on behalf of APCo (376 MW), CSP (50 MW), I&M (150 MW), KPCo (100 MW), and OPCo (50 MW). Regulatory approvals have been received for some of these contracts in four of the five states (Virginia, West Virginia, Indiana, and Michigan), however two states, Virginia and Kentucky, denied inclusion of wind PPA costs. Virginia denied three contracts totaling 201 MW (Grand Ridge II, Grand Ridge III, and Beech Ridge), while Kentucky denied the 100 MW FPL Energy wind contract (Lee- Dekalb). No approval was sought or received in Ohio.

2) **DSM Jurisdictional Activity:**

Indiana:
▪ Included in the Phase II Order of Cause 42693 are rules dictating the process for the development and implementation of energy efficiency programs. I&M has several "core-plus" and "core" programs that have Commission approval are expected to be implemented in 2010. During 2010, "core" programs will be transitioned to the State-wide third-party administrator.
Michigan:
▪ Energy Optimization (energy efficiency) and renewable standards are included as part of a comprehensive energy law enacted in 2008.
▪ On Dec. 19, 2008, I&M filed with the MPSC intent to use the State Independent Energy Optimization Program Administrator to meet the requirements of the law.
Kentucky:
▪ Reestablished industrial collaborative process to begin offering programs to serve this customer class.
Ohio:
▪ Three-year program plans filed in 2009 (Case No. 09-1090-EL-POR) for compliance with S.B. 221.
West Virginia:
• APCo filed for a three-year program for energy efficiency in June, 2010 and is awaiting a ruling from the Commission.

3) **Dresden CC Unit** (2013): The partially built, 540MW (summer) unit has been purchased. Completion of construction is scheduled prior to June 1, 2013.

4) **NG Combustion Turbines** (2017 and 2018): Given the uncertainty surrounding efforts (or ability given the current RPM protocol) to either: 1) purchase PJM market capacity in the future; or 2) identify opportunities and acquire additional distressed assets, steps will ultimately need to be undertaken internally to evaluate Greenfield or Brownfield-site construction of CT capacity in the East Zone.

- *The New Generation Development siting advisory group* has performed evaluations to establish a short-list, from a list of 40 potential sites–most of which are located in Ohio, Virginia, or West Virginia–originally identified by the group in April 2006. Such siting studies are intended to screen, score and rank potential CT or CC sites based on a multitude of factors and will be updated in the future as necessary.
- *Generation Asset Purchase Opportunities*: Although some years remain before concrete action would be needed to have a greenfield CT plant on by 2017, AEP continues to monitor the regional market for potential asset purchase opportunities.

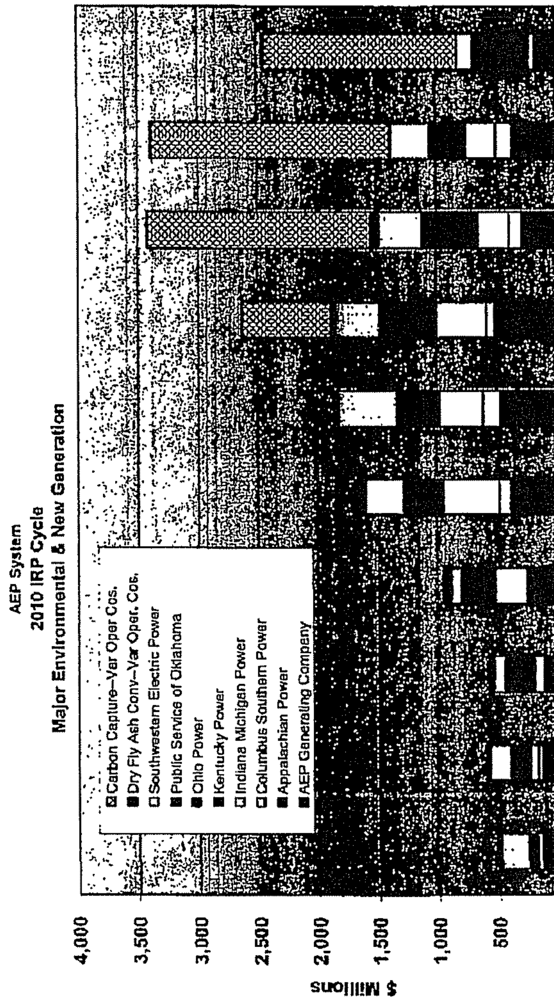
5) **Solar** (2010-2012): AEP-Ohio has a PPA for 10 MW of solar capacity which began commercial operation in June, 2010. This will meet the solar benchmarks included in SB 221 through 2011. Solar benchmarks for 2010, 2011 and 2012 are 5 GWh, 15 GWh, and 29 GWh respectively, as shown in Exhibit 2-3.

To implement the recommendations included in this plan, significant capital expenditures will be required. As stated earlier, this plan, while making specific recommendations based on available data, is not a commitment to a specific course of action.

12.5 Plan Impacts on Capital Spending

This Plan includes new capacity resource additions, as described, as well as unit uprates and assumed environmental retrofits. Such generation additions require a *significant* investment of capital. Some of these projects are still conceptual in nature, others do not have site-specific information to perform detailed estimates; however, it is important to provide an order of magnitude cost estimate for the projects included in this plan. As some of the initiatives represented in this plan span both East and West AEP zones, **Exhibit 12-4** includes estimates for such projects over the entire AEP System.

Exhibit 12-4: Incremental Capital Spending Impacts of the IRP



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Carbon Capture--Var Oper Cos.	-	-	-	-	-	-	746	1,861	2,000	1,818
Dry Fly Ash Conv--Var Oper. Cos.	-	12	34	52	86	28	43	62	-	-
Southwestern Electric Power	236	187	95	87	320	488	356	377	330	142
Public Service of Oklahoma	6	9	0	6	127	268	356	364	172	299
Ohio Power	40	49	88	77	85	28	30	38	62	63
Kentucky Power	23	104	174	207	145	75	76	56	65	78
Indiana Michigan Power	47	70	81	257	458	360	416	261	252	19
Columbus Southern Power	21	27	20	25	100	141	69	103	133	55
Appalachian Power	107	52	66	185	248	222	141	83	122	155
AEP Generating Company	5	90	37	50	140	253	380	232	252	18

Source: AEP Resource Planning

It is important to reiterate the capital spend level reflected on the **Exhibit 12-4** is "incremental" in that it does not include "Base"/business-as-usual capital expenditure requirements of the generating facilities sector or transmission and distribution capital requirements. Achieving this additional level of expenditure will therefore be a significant challenge going-forward and would suggest the Plan itself *will remain under constant evaluation and is subject to change* as, particularly, new AEP's system-wide and operating company-specific "Capital Allocation" processes continue to evolve. Also, while the spend level includes cost to install Carbon Capture equipment, these projects are included <u>only</u> under the assumption that any comprehensive GHG/CO_2 bill requiring significant reductions in CO_2 emissions will include a provision to receive credits or allowances that would largely offset the cost of such equipment.

12.6 Plan Impact on CO_2 Emissions (*"Prism" Analysis)*

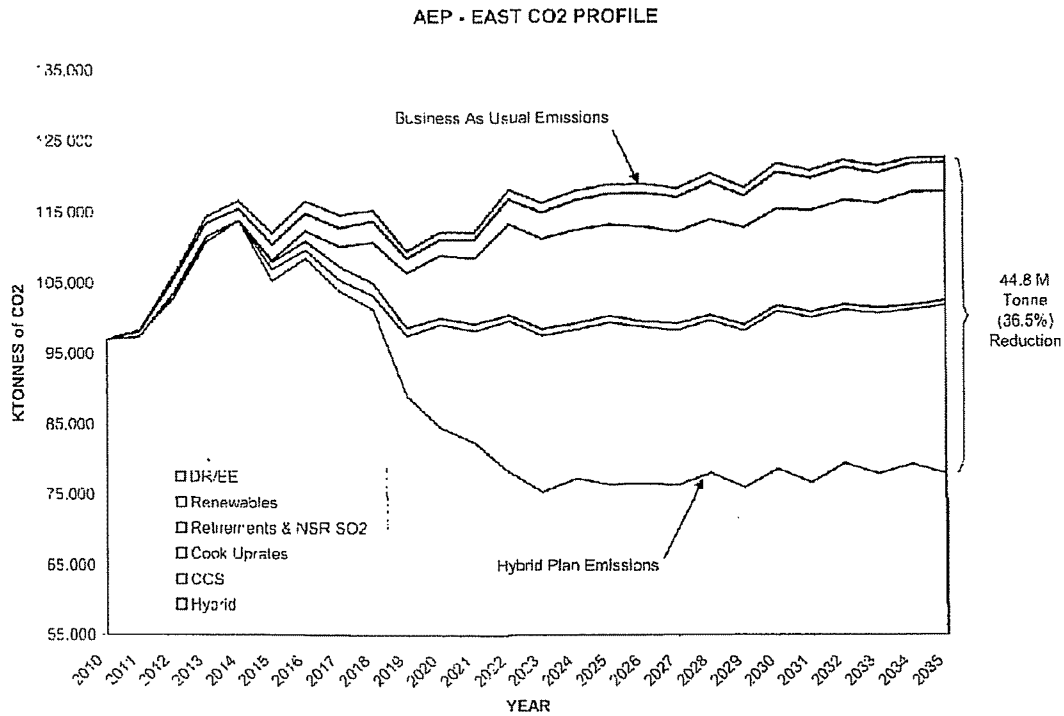
The Hybrid Plan includes resource additions that will result in lowering AEP's carbon emissions over the next 20 years. By retiring older, less efficient coal fired units, increasing nuclear capacity at the Cook plant, adding wind and solar resources, adding carbon capture and storage to larger coal units, and implementing energy efficiency programs, AEP has laid out a plan that is consistent with pending legislation and corporate sustainability.

To gauge those respective CO_2 mitigation impacts incorporated into this resource planning, an assessment was performed that emulates an approach undertaken by the Electric Power Research Institute (EPRI). This profiling seeks to measure the contributions of various "portfolio" components that could, when taken together, effectively achieve such carbon mitigation through:

- Energy Efficiency
- Renewable Generation
- Fossil Plant Efficiency, including coal-unit retirements
- Nuclear Generation
- Technology Solutions, including Carbon Capture and Storage

The following **Exhibit 12-5** reflects those comparable components within this 2010 IRP as set forth as a multi-colored "prism" that are anticipated to contribute to the overall AEP-East system's initiatives to reduce its carbon footprint:

Exhibit 12-5: AEP-East System CO_2 Emission Reductions, by "Prism" Component



Source: AEP Resource Planning

12.7 Conclusions

The recommended AEP-East capacity resource plan **provides the lowest reasonable cost solution through a combination of traditional supply, renewable and demand-side resources**. The most recent (April 2010) "tempered" load growth, combined with the completion of the Dresden natural gas-combined cycle facility, additional renewable resources, increased DR/EE initiatives, and the proposed capacity uprate of the Cook Nuclear facility allow AEP-East region to meet its reserve requirements until the 2018-2019 timeframe, at which point modeling indicates new peaking capacity will be required. Other than the aforementioned D.C. Cook uprate, no new baseload capacity is required over the 10-year Planning Period.

The Plan also positions the AEP-East Operating Companies to achieve legislative or regulatory mandated state renewable portfolio standards and energy efficiency requirements, and sets in place the framework to meet potential CO_2 reduction targets and emerging U.S. EPA rulemaking around HAPs and CCR at the intended least reasonable cost to its customers.

The resource planning process is becoming increasingly complex given these uncertainties as well as spiraling technological advancements, changing economic and other energy supply fundamentals, uncertainty around demand and energy usage patterns as well as customer acceptance for embracing efficiency initiatives. All of these uncertainties necessitate flexibility in any on-going plan. Moreover, the ability to invest in capital-intensive infrastructure is increasingly challenged in light of current economic conditions, and the impact on the AEP-East Operating Companies' customer costs-of-service/rates will continue to be a primary planning consideration.

Other than those initiatives that fall within some necessary "actionable" period over the next 2-3 years, this long-term Plan is also not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative and regulated proposals to control greenhouse gases and numerous other hazardous pollutants… all of which will likely result in either the retirement or costly retrofitting of all existing AEP-East coal units.

Finally, bear in mind that the planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported here reflects, to a large extent, assumptions that are clearly subject to change. In summary, it represents a very reasonable "snapshot" of future requirements at this particular point in time.

APPENDICES

Appendix A, Figure 1 Existing Generation Capacity, AEP-East Zone

AEP System - East Zone
(Including Buckeye Power Capacity per Operating Agreement)
Existing Generation Capacity as of June 1, 2010

Plant Name	Unit No.	In-Service Date		AEP Own/ Contract	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR Installation Year	FGD Installation Year	Super Critical	Age
					APCo						
Amos	1	1971		O	790	800	Coal	2005	2011	Y	39
Amos	2	1972		O	790	790	Coal	2004	2010	Y	38
Amos	3	1973		O	433	428	Coal	2004	2009	Y	37
Clinch River	1	1958		O	235	230	Coal	--	--	N	52
Clinch River	2	1958		O	235	230	Coal	--	--	N	52
Clinch River	3	1961		O	235	230	Coal	--	--	N	49
Glen Lyn	5	1944		O	95	90	Coal	--	--	N	66
Glen Lyn	6	1957		O	240	235	Coal	--	--	N	53
Kanawha River	1	1953		O	200	200	Coal	--	--	N	57
Kanawha River	2	1953		O	200	200	Coal	--	--	N	57
Mountaineer	1	1980		O	1,314	1,299	Coal	2004	2007	Y	30
Sporn	1	1950		O	150	145	Coal	--	--	N	60
Sporn	3	1951		O	150	145	Coal	--	--	N	59
APCo Coal					5,067	5,022					42
Ceredo	1-6	2001	(a)	O	516	450	Gas (CT)	--	--	N	9
APCo Gas					516	450					9
APCo Hydro		Various		O	92	50	Hydro	--	--		
Summersville	1-2	2001		C	28	14	Hydro	--	--		9
APCo Hydro			(b)		119	64					9
Smith Mountain	1	1965		O	66	66	PSH	--	--	--	45
Smith Mountain	2	1965		O	174	174	PSH	--	--	--	45
Smith Mountain	3	1980		O	105	105	PSH	--	--	--	30
Smith Mountain	4	1966		O	174	174	PSH	--	--	--	44
Smith Mountain	5	1966		O	66	66	PSH	--	--	--	44
APCo Pumped Storage					585	585					42
APCo Wind		Various	(c)	C	58	45	Wind	--	--	--	
Total APCo					**6,346**	**6,166**					
					Cardinal-Buckeye						
Cardinal	2	1967		C	595	585	Coal	2004	2008	Y	43
Cardinal	3	1977		C	630	630	Coal	2004	2012	Y	33
Buckeye Coal					1,225	1,215					38
Robert Mone	1-3	2001	(d)	C	134	44	Gas (CT)	--	--	--	9
Buckeye Gas					134	44					9
Total Buckeye					**1,359**	**1,259**					
					CSP						
Beckjord	6	1969		O	52	52	Coal	--	--	N	41
Conesville	3	1962		O	165	165	Coal	--	--	N	48
Conesville	4	1973		O	337	337	Coal	2009	2009	Y	37
Conesville	5	1976		O	400	400	Coal	2015	1976	N	34
Conesville	6	1978		O	400	400	Coal	2015	1978	N	32
Picway	5	1955		O	100	95	Coal	--	--	N	55
Stuart	1	1971		O	151	151	Coal	2004	2008	Y	39
Stuart	2	1970		O	151	151	Coal	2004	2008	Y	40
Stuart	3	1972		O	151	151	Coal	2004	2008	Y	38
Stuart	4	1974		O	151	151	Coal	2004	2008	Y	36
Zimmer	1	1991		O	330	330	Coal	2004	1991	Y	19
CSP Coal					2,388	2,383					35
Waterford	1-6	2002	(a)	O	840	810	Gas (CC)	2002	--	N	8
Darby	1-6	2002	(e)	O	507	438	Gas (CT)	2002	--	N	8
Lawrenceburg	1-6	2004	(e)	O	1,186	1,120	Gas (CC)	--	--	N	6
Stuart Diesel	1-4	1969		O	3	3	Oil (Diesel)	--	--	N	41
CSP Gas/Oil					2,536	2,371					7
CSP Wind		Various	(c)	C	7	7	Wind	--	--	--	
CSP Solar		Various	(f)	C	1	2	Solar	--	--	--	
Total CSP					**4,931**	**4,762**					

(a) Acquired in 2005
(b) Hydro capacity is rated at expected annual average output
(c) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit. 13% of the nameplate capacity
(d) The listed Mone capacity is the net impact of the various contracts with Buckeye Power
(e) Acquired in 2007 by AEP Generating Co. CSP receives capacity and energy via agreement
(f) The capacity of the Solar Energy Projects are listed at the preliminary PJM credit. 6.67%(winter) and 38%(summer) of the nameplate capacity

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Appendix A, Figure 2 Existing Generating Capacity, AEP-East Zone (cont'd)

AEP System - East Zone
(Including Buckeye Power Capacity per Operating Agreement)
Existing Generation Capacity as of June 1, 2010

Plant Name	Unit No.	In-Service Date		AEP Own/ Contract	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR Installation Year	FGD Installation Year	Super Critical	Age
					I&M						
Rockport	1	1984		O	1,122	1 118	Coal	2017	2017	Y	26
Rockport	2	1989		C	1,105	1,105	Coal	2019	2019	Y	21
Tanners Creek	1	1951		O	145	145	Coal	--	--	N	59
Tanners Creek	2	1952		O	145	145	Coal	--	--	N	58
Tanners Creek	3	1954		O	205	195	Coal	--	--	N	56
Tanners Creek	4	1964		O	500	500	Coal	--	--	Y	46
I&M Coal					3,222	3,208					32
I&M Hydro			(b)		15	11	Hydro	--	--	--	
Cook Nuclear	1	1975		O	994	972	Nuclear	--	--	--	35
Cook Nuclear	2	1978		O	1,121	1,057	Nuclear	--	--	--	32
I&M Nuclear					2,115	2,029					33
I&M Wind		Various	(c)	C	22	22	Wind	--	--	--	
Total I&M					**5,374**	**5,270**					
					KPCo						
Big Sandy	1	1963		O	278	273	Coal	--	--	N	47
Big Sandy	2	1969		O	800	800	Coal	2004	2015	Y	41
Rockport	1	1984		O	198	197	Coal	2017	2017	Y	26
Rockport	2	1989		C	195	195	Coal	2019	2019	Y	21
KPCo Coal					1,471	1,465					37
Total KPCo					**1,471**	**1,465**					**37**
					OPCo						
Amos	3	1973		O	867	857	Coal	2004	2009	Y	37
Cardinal	1	1967		O	595	585	Coal	2004	2008	Y	43
Gavin	1	1974		O	1.320	1,315	Coal	2004	1994	Y	36
Gavin	2	1975		O	1.320	1,315	Coal	2004	1994	Y	35
Kammer	1	1958		O	210	200	Coal	--	--	N	52
Kammer	2	1958		O	210	200	Coal	--	--	N	52
Kammer	3	1959		O	210	200	Coal	--	--	N	51
Mitchell	1	1971		O	770	770	Coal	2007	2007	Y	39
Mitchell	2	1971		O	790	790	Coal	2007	2007	Y	39
Muskingum River	1	1953		O	205	190	Coal	--	--	N	57
Muskingum River	2	1954		O	205	190	Coal	--	--	N	56
Muskingum River	3	1957		O	215	205	Coal	--	--	N	53
Muskingum River	4	1958		O	215	205	Coal	--	--	N	52
Muskingum River	5	1968		O	600	600	Coal	2005	2015	Y	42
Sporn	2	1950		O	150	145	Coal	--	--	N	60
Sporn	4	1952		O	150	145	Coal	--	--	N	58
Sporn	5	1960		O	0	0	Coal	--	--	Y	50
OPCo Coal					8,032	7,912					41
OPCo Hydro		1983	(b)	O	26	20	Hydro	--	--	--	27
OPCo Wind		Various	(c)	C	7	7	Wind	--	--	--	
OPCo Solar		Various	(e)	C	1	2	Solar	--	--	--	
Total OPCo					**8,064**	**7,941**					

(b) Hydro capacity is rated at expected annual average output.
(c) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit, 13% of the nameplate capacity
(f) The capacity of the Solar Energy Projects are listed at the preliminary PJM credit, 6.67%(winter) and 38%(summer) of the nameplate capacity

		Winter	Summer
TOTAL AEP-East (excl. OVEC)		27,546	26,863
OVEC Purchase Entitlement		980	947
TOTAL AEP-East		28,526	27,810
Totals by type	Coal	22,385	22,152
	Nuclear	2,115	2,029
	Hydro	745	680
	Gas/Diesel	3,186	2,865
	Wind	93.30	80.30
	Solar	1.36	3.84
	Total	**28,526**	**27,810**

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Appendix B, Figure 1 Assumed FGD Scrubber Efficiency and Timing

Units	Current Scrubber Efficiency - % 2010	New - FGD Installs Month / Year	New - FGD Installs Scrubber Efficiency - %	FGD - Upgraded Month / Year	FGD - Upgraded Scrubber Efficiency - %
Amos 1	-	Feb-11	95.0	Apr-11	96.0
Amos 2	-	Mar-10	96.0		
Amos 3	97.0	-	-	-	-
Big Sandy 2	-	Jun-15	98.0	-	-
Cardinal 1	95.5	-	-	-	-
Cardinal 2	95.5	-	-	-	-
Cardinal 3	-	Jan-12	95.0	Jan-13	96.5
Conesville 4	94.5	-	-	Jan-11	97.0
Conesville 5	96.0	-	-	-	-
Conesville 6	96.0	-	-	-	-
Gavin 1	94.5	-	-	-	-
Gavin 2	95.0	-	-	-	-
Mitchell 1	97.7	-	-	-	-
Mitchell 2	98.0	-	-	-	-
Mountaineer 1	98.5	-	-	Jan-18	98.0
Rockport 1	-	Jun-17	95.0	-	-
Rockport 2	-	Jun-19	95.0	-	-
Stuart 1-4	97.0	-	-	-	-
Zimmer 1	93.0	-	-	-	-

Notes:
Assumed scrubber efficiencies per T. A. March (4/23/10), Amos 1 per WSR (4/23/10)
Delayed FGD in-service per MSC10-3 maintenance schedule, thus delayed scrubber upgrade 1 month.

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Appendix B, Figure 2 Assumed Capacity Changes Incorporated into Long Range Plan

AEP Eastern Fleet

Anticipated Capacity Changes Incorporated into Long-Range Planning

Unit / Amount / Timing

	Capacity Rating NDC (MW)	HP/1st RH Turbine ADSP Improvement (18 MW)	In-Service Date	HP/1st RH Turbine ADSP Improvement 800 series (12 MW)	In-Service Date	HP ADSP Turbine Improvement 1300 series (20-MW)	In-Service Date	Main StopValve - MSV/CV Changeout (35-MW)	In-Service Date	Carbon Capture Project (Comm. Oper.)	In-Service Date	FGD Derate (MW)	Net (MW) after FGD	In-Service Date
Amos 1	800			812	Feb-11							(22)	790	Feb-11
Big Sandy 1	260	278	Jan-10											
Big Sandy 2	800											(40)	760	Jun-15
Cardinal 1	595													
Cardinal 2	595													
Cardinal 3	630											(10)	620	Jan-12
Gavin 1	1320					0	Jun-09			1125	Jan-20			
Gavin 2	1320					0	Jun-11							
Mountaineer 1	1314									1256	Nov-15			
Mountaineer 1	1256									1125	Jan-19			
Rockport 1	1320							1355	Jun-17			(35)	1320	Jun-17
Rockport 2	1300							1335	Jun-19			(35)	1300	Jun-19

Sources:
1) Increase in capacity shown at Big Sandy 1 (18-MW), Cardinal 1+2 capacity increase from 580-MW to 595-MW with a summer derate in May-Oct per N. Akins (2/15/10).
2) The 20-MW capacity increase at both Gavin 1+2 have been removed in June of 2009 & 2011, however there is a heat rate improvement per D. L. Untch/D. M. Collins (5/27/09). To be consistent with the AEP-East Capacity update per N. Akins (2/15/10), the forecast will show a 5-MW derate in July & August.
3) Revised main stop valve (MSV) ratings of 35-MW per M. A. Gray (8/30/06).
4) Mountaineeer 1 includes a a seasonal derate in the periods Jun-Sep per R. E. Dool (2/04/10).
5) Carbon Capture project which began in October 2009 will reflect a 6-MW capacity reduction. The 2010 Strategic Plan CLR (2/09/10) assumes the commercial operation of carbon capture at Mountaineer; capacity reduction of an additional (58-MW) 11/2015 and (131-MW) 1/2019 for a total of 195-MW.
6) Forecast shows a capacity reduction for CCS of 195-MW at Gavin 1 effective 1/2020 per the 2010 Strategic Plan.
7) No change in unit capacity after the MSV/FGD are installed at Rockport 1+2 per D. L. Untch/D. M. Collins (1/14/10).
8) The FGD at Amos 1 has been delayed from 1/1/2011 to 2/1/2011, and the FGD at Muskingum 5 has been cancelled

Appendix C, Key Supply Side Resource Assumptions

AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) Std. ISO	Trans. Cost (e) ($/kW)	Emission Rates SO_2 (g) (Lb/mmBtu)	Emission Rates NO_x (Lb/mmBtu)	Emission Rates CO_2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load							
Pulv. Coal (Ultra-Supercritical) (h)	618	24	0.07	0.070	205.3	85	89.6
CFB (h)	585	26	0.07	0.070	210.3	80	90.7
IGCC ("F"Class)(h)	630	24	0.01	0.057	205.3	85	87.5
IGCC ("H"Class)(h)	862	17	0.01	0.057	205.3	85	87.5
Nuclear (US ABWR)	1,606	64	0.00	0.000	0.0	90	94.0
Base Load (90% CO2 Capture New Unit)							
Pulv. Coal (Ultra-Supercritical) (h)	526	29	0.0708	0.070	20.5	85	89.6
CFB (w/ CCS, Amine, NOAK)(h)	497	30	0.0665	0.070	20.5	80	89.6
IGCC ("F"Class, w/ CCS, NOAK)(h)	535	28	0.0090	0.057	20.5	86	87.5
IGCC ("F"Class w/ 20% Biomass, w/ CCS)(h)	482	31	0.0090	0.057	11.4	85	87.5
IGCC ("H"Class, w/ CCS)(h)	776	19	0.0090	0.057	20.5	85	87.5
Intermediate							
Combined Cycle (1X1 GE7FA)	255	60	0.0007	0.008	116.0	25	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	621	60	0.0007	0.008	116.0	60	89.1
Combined Cycle (1X1 GE7FH)	385	60	0.0007	0.008	116.0	25	89.1
Combined Cycle (1X1 SW501G)	387	60	0.0007	0.008	116.0	25	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	652	60	0.0007	0.008	116.0	60	89.1
Combined Cycle (2X1 M701G)	962	60	0.0007	0.008	116.0	60	89.1
Intermediate (90% CO2 Capture New Unit)							
Combined Cycle (2X1 GE7FB, w/ Amine Scrubbing)	554	71	0.0007	0.008	11.6	60	89.1
Combined Cycle (2X1 M701G, w/ Chilled Ammonia)	818	71	0.0007	0.008	11.6	60	89.1
Peaking							
Combustion Turbine (2X1GE7EA)	164	57	0.0007	0.009	116.0	3	90.1
Combustion Turbine (2X1GE7EA,w/ Inlet Chillers)	164	59	0.0007	0.009	116.0	3	90.1
Combustion Turbine (2X1GE7FA)	332	57	0.0007	0.009	116.0	3	90.1
Combustion Turbine (2X1GE7FA, w/ Inlet Chillers)	332	59	0.0007	0.009	116.0	3	90.1
Aero-Derivative (1X GE LM6000PF)	46	60	0.0007	0.056	116.0	3	89.1
Aero-Derivative (1X GE LM6000PC)	60	60	0.0007	0.056	116.0	90	89.1
Aero-Derivative (1X GE LMS100PB, w/ Inlet Chillers)	98	59	0.0007	0.009	116.0	30	90.1
Aero-Derivative (2X GE LMS100PB, w/ Inlet Chillers)	196	59	0.0007	0.009	116.0	3	90.1
CAES Facility	300	60	0.0007	0.008	116.0	47	96.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2010 dollars. Assume 2.0% escalation rate for 2010 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(d) *Total Plant & Interconnection Cost w/AFUDC (AEP-East rate of 4.90%, site rating $/kW).*
(e) Transmission Cost ($/kW,w/AFUDC).
(f) Levelized Fuel Cost (40-Yr. Period 2011-2050)
(g) Based on 4.5 lb. Coal.
(h) Pittsburgh #8 Coal.

Appendix D, AEP-East Summer Peak Demands, Capabilities and Margins

AEP SYSTEM - EASTERN ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (April 2010) Load Forecast
2010 IRP (Hybrid Prime)

Planning Year	Obligation to PJM: Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req'l (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Resources: Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions: Units	Planned Capacity Additions: MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	AEP Position (MW): Net Position w/o New Capacity	Net Position w/ New Capacity
2007 /08 (k)	21,087	(1)		21,087	439	0.957	1.079	22,301	1,391	23,692	28,769	2,574				26,195	7.61%	24,202	510	510
2008 /09 (k)	21,326	(1)		21,326	439	0.958	1.080	22,570	1,400	23,970	28,630	1,793				27,037	7.65%	24,969	999	999
2009 /10 (k)	21,642	(58)	(1)	21,641	473	0.957	1.080	22,873	1,400	24,273	28,807	1,131				27,676	8.41%	25,348	1,075	1,075
2010 /11 (k)	20,395	(16)	(1)	20,394	445	0.955	1.083	21,631	1,405	23,030	28,417	1,207	10 MW Solar & 250 MW Wind	36	0	27,246	10.90%	24,278	1,208	1,240
2011 /12 (k)	20,674	(206)	(59)	20,615	445	0.955	1.083	21,871	1,388	23,267	28,412	1,492	10 MW Solar & 100 MW Wind	17	0	26,973	6.95%	24,559	1,244	1,292
2012 /13 (k)	21,375	(399)	(16)	21,350	445	0.950	1.080	22,005	1,398	24,001	27,083	873	10 MW Solar & 100 MW Wind	17	0	27,080	7.26%	25,114	1,048	1,113
2013 /14 (k)	21,741	(651)	(206)	21,536	445	0.957	1.080	22,806	1,396	24,202	27,675	(4)	540 MW D CC2 & 10 MW Solar & 100 MW Wind	557	0	28,606	7.95%	26,240	1,461	2,038
2014 /15	20,755	(932)	(399)	20,356	445	0.957	1.080	21,532	1,399	22,928	27,256	(4)	26 MW Solar & 300 MW Wind	49	0	27,936	5.19%	25,048	2,099	2,720
2015 /16	20,869	(1,163)	(651)	20,218	445	0.957	1.080	21,382	1,395	22,778	26,401	(4)	26 MW Solar & 400 MW Wind	62	0	27,143	8.02%	24,968	1,509	2,108
2016 /17	20,967	(1,237)	(932)	20,035	445	0.957	1.080	21,184	1,398	22,580	25,294	(4)	26 MW Solar & 250 MW Wind	42	0	26,079	6.00%	24,514	1,200	1,934
2017 /18	21,093	(1,312)	(1,153)	19,940	446	0.967	1.080	21,082	1,396	22,478	24,697	(4)	314 MW CT* & 28 MW Solar & 150 MW Wind	343	0	26,826	6.34%	24,446	904	1,968
2018 /19	21,224	(1,377)	(1,237)	19,987	445	0.957	1.080	21,133	1,395	22,528	24,234	(4)	314 MW CT* & 28 MW Solar & 50 MW Wind	330	0	25,693	5.09%	24,385	475	1,858
2019 /20	21,361	(1,465)	(1,312)	20,039	445	0.957	1.080	21,189	1,396	22,565	22,658	(4)	28 MW Solar & 100 MW Wind	23	0	24,140	5.02%	22,928	(1,061)	343
2020 /21	21,391	(1,569)	(1,377)	20,013	445	0.957	1.080	21,161	1,396	22,557	22,658	(4)	26 MW Solar & 150 MW Wind	29	0	24,169	5.02%	22,958	(1,033)	399

Notes: (a) Based on (April 2010) Load Forecast (with implied PJM diversity factor)
Includes Monongahela Power & NCEMC

(b) Existing plus approved DR, EE, and IVV

(c) The impact of new DSM is delayed two years to represent either
(1) its impact on actual load feeding through the PJM load forecast process or
(2) verification prior to being offered into the PJM RPM auction.

(d) Demand Response approved by PJM in the prior planning year

(e) Installed Reserve Margin (IRM) = 15.0% through 2009/10, 15.5% through 2011/2012, then 16.2%
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes:
FRR view of obligations only.
Buckeye Cardinal and Mone obligations

(g) Reflects the following summer capability assumptions:
AEP share of OVEC capacity
Assumes hydro units, including Summersville, are derated to August average output in 2014/15
WIND FARM (nameplate):
275 MW Total
EFFICIENCY IMPROVEMENTS:
2007/08: Cardinal 2: 0 MW (turbine) (offset to FGD derate)
2008/09: Rockport 1: 20 MW (turbine); Amos 3: 36 MW (valve)
2009/10: Amos 2: 12 MW (turbine); Big Sandy 1: 0 MW (turbine); Gavin 1: 0 MW (turbine)
2010/11: Amos 1: 12 MW (turbine)
2011/12: Cook 2: 14 MW (Uprate); Gavin 2: 0 MW (turbine)
2014/15: Cook 2: 45 MW (Uprate)
2015/16: Cook 1: 100 MW (Uprate); Cook 2: 68 MW (Uprate)
2016/17: Cook 1: 68 MW (Uprate)
2017/18: Cook 2: 68 MW (Uprate); Rockport 1: 35 MW (valve) (offset to FGD derate)
2018/19: Cook 1: 68 MW (Uprate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

(g) continued
CCS DERATES:
2009/10: Mountaineer 1: 6 MW
2015/16: Mountaineer 1: 58 MW
2018/19: Mountaineer 1: 131 MW
2019/20: Gavin 1: 155 MW
2021/22: Amos 3: 106 MW
FGD DERATES:
2007/08: Cardinal 1&2: 20 MW each; Stuart 1-4: 1 MW each
2008/09: Amos 3: 35 MW
2009/10: Amos 2: 22 MW; Conesville 4: 2 MW
2010/11: Amos 1: 22 MW; Kyger Creek 4-5: 3 MW each
2011/12: Cardinal 3: 10 MW; Kyger Creek 1-3: 3 MW each
2012/13: Clifty Creek 4,6: 2 MW each
2013/14: Clifty Creek 1-3,5: 2 MW each
2015/16: Big Sandy 2: 40 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2009/10: Conesville 4: 0 MW
2019/20: Conesville 5-6: 4 MW each
2020/21: Rockport 1: 0 MW
2022/23: Rockport 2: 0 MW
RETIREMENTS:
2010/11: Sporn 5
2012/13: Conesville 3; Muskingum River 2,4
2014/15: Muskingum River 1,3
2015/16: Glen Lyn 5-6; Muskingum River 5
2016/17: Tanners Ck. 1-3; Clinch R. 1-3
2017/18: Picway 5; Sporn 1-4
2018/19: Kanawha River 1&2
2019/20: Kammer 1-3; Big Sandy 1; Tanners Ck. 4

(h) Includes:
CP&L Rockport sale through 2009/10
East-West transfer of 250 MW in 2007/08
Sale of 50 MW to Wisconsin Public Service in 2007/08
Sale of 100 MW to Wolverine in 2007/08 - 2009/10, netted
against a 100 MW purchase from Dynegy in 2007/08
Constellation purchase of 315 MW in 2009/10-2011/12
Purchase to cover CSP's former Monongahela Power load
in 2007/08 - 2009/10
Darby and Lawrenceburg are sold in the 2007/08 RPM auction
(by AEP and PSEG)
MISO Sale of 348 MW in 2008/09 and 25 MW in 2009/10
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA
2010/11-2012/13 (45 MW, 374 MW, 157 MW)
RPM Auction Sales 2007/08 - 2012/13 (777 MW, 1406 MW, 1389 MW
, 1463 MW, 1404 MW, 690 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30/07

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Appendix E, Plan to Meet 10% of Renewable Energy Target by 2020

AEP System - East Zone

Potential Renewables Profile to Achieve a System-Wide 10% Target by 2020, and 15% by 2030 [a]
as well as Known or Emerging State Mandates
2010 IRP

APCo

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	75	0	0.8%
2010	0	278	0	2.7%
2011	0	378	0	3.0%
2012	0	378	0	3.6%
2013 (b)	0	378	0	3.5%
2014	0	378	0	3.5%
2015	0	378	0	3.5%
2016	0	378	0	3.5%
2017	0	378	0	3.5%
2018	0	378	0	3.4%
2019	0	378	0	3.4%
2020	0	378	0	3.4%
2021	0	378	0	3.3%
2022	0	408	0	3.8%
2023	0	409	0	3.6%
2024	0	409	0	3.6%
2025	0	409	0	3.5%
2026	0	408	0	3.6%
2027	0	409	0	3.4%
2028	0	409	0	3.4%
2029	0	409	0	3.4%
2030	0	409	0	3.3%

CSP

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	0	0	0.0%
2010	0	60	0	0.8%
2011	8	90	2	0.9%
2012	13	100	2	1.7%
2013 (b)	17	125	2	2.1%
2014	28	160	27	3.6%
2015	38	190	27	4.2%
2016	40	273	25	5.5%
2017	58	323	25	6.4%
2018	71	323	76	8.6%
2019	83	373	75	9.4%
2020	95	448	75	10.7%
2021	113	448	75	10.8%
2022	126	616	76	12.0%
2023	128	615	75	13.5%
2024	147	685	75	14.4%
2025	147	715	75	15.1%
2026	156	765	75	16.0%
2027	158	815	94	17.3%
2028	169	865	84	18.0%
2029	169	865	94	17.9%
2030	185	866	94	17.8%

I&M

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	0	0	0.0%
2010	0	150	0	2.5%
2011	0	150	0	2.5%
2012	0	150	0	2.4%
2013 (b)	0	200	0	3.2%
2014	0	350	0	5.8%
2015	0	850	0	10.2%
2016	0	850	0	10.3%
2017	0	850	0	10.3%
2018	0	650	0	10.3%
2019	0	850	0	10.4%
2020	0	850	0	10.3%
2021	0	700	0	11.0%
2022	0	700	0	11.0%
2023	0	700	0	10.9%
2024	0	750	50	13.7%
2025	0	800	50	14.3%
2026	0	850	60	16.0%
2027	0	850	50	14.9%
2028	0	850	50	14.8%
2029	0	850	50	14.7%
2030	0	850	50	14.7%

KPCo

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	0	0	0.0%
2010	0	0	0	0.0%
2011	0	0	0	0.0%
2012	0	0	0	0.0%
2013 (b)	0	0	0	0.0%
2014	0	100	0	4.2%
2015	0	100	0	4.2%
2016	0	100	0	4.2%
2017	0	100	0	4.2%
2018	0	100	0	4.2%
2019	0	100	0	4.1%
2020	0	100	0	4.1%
2021	0	150	0	6.1%
2022	0	160	0	6.0%
2023	0	150	0	6.0%
2024	0	150	50	11.1%
2025	0	150	50	11.1%
2026	0	160	50	11.0%
2027	0	200	63	14.1%
2028	0	200	63	14.0%
2029	0	200	63	13.9%
2030	0	200	63	13.8%

OPCo

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	0	0	0.0%
2010	0	50	0	0.6%
2011	12	60	42	1.3%
2012	17	100	42	1.8%
2013 (b)	24	125	42	2.1%
2014	39	150	67	3.2%
2015	55	210	67	3.9%
2016	71	377	25	5.1%
2017	87	477	25	6.3%
2018	101	527	75	8.4%
2019	115	577	75	9.0%
2020	130	652	75	9.9%
2021	142	662	125	11.5%
2022	178	632	125	11.0%
2023	178	752	125	12.7%
2024	193	802	125	13.3%
2025	198	862	125	13.8%
2026	208	902	125	14.4%
2027	208	952	144	15.4%
2028	220	1,002	144	15.9%
2029	220	1,002	144	15.8%
2030	236	1,002	144	15.8%

AEP-Ohio

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	0	0	0.0%
2010	0	100	0	0.7%
2011	20	100	44	1.1%
2012	31	200	44	1.8%
2013 (b)	41	250	44	2.1%
2014	67	300	94	3.3%
2015	94	400	94	4.0%
2016	120	650	50	5.3%
2017	148	800	50	6.3%
2018	172	850	150	8.4%
2019	198	950	150	9.1%
2020	225	1,100	150	10.2%
2021	258	1,100	200	11.2%
2022	301	1,167	200	11.8%
2023	301	1,367	200	13.1%
2024	345	1,467	200	13.8%
2025	345	1,567	200	14.4%
2026	384	1,667	200	15.0%
2027	384	1,767	238	16.2%
2028	389	1,867	238	16.6%
2029	389	1,867	238	16.7%
2030	420	1,867	238	16.7%

AEP-East

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	75	0	0.2%
2010	0	528	0	1.8%
2011	20	628	44	2.1%
2012	31	726	44	2.3%
2013 (b)	41	826	44	2.6%
2014	67	1,126	94	3.8%
2015	94	1,526	94	5.0%
2016	120	1,776	50	6.6%
2017	148	1,926	50	6.0%
2018	172	1,976	150	6.9%
2019	198	2,076	150	7.2%
2020	225	2,226	150	7.6%
2021	258	2,326	200	8.3%
2022	301	2,426	200	8.6%
2023	301	2,620	200	9.1%
2024	345	2,770	300	10.2%
2025	345	2,920	300	10.5%
2026	364	3,076	300	10.9%
2027	364	3,226	350	11.6%
2028	389	3,326	350	11.6%
2029	389	3,326	350	11.7%
2030	420	3,326	350	11.7%

(a) Data excludes conventional (run-of-river) hydro energy as a renewable source as it has been excluded from certain state and proposed federal RPS criteria.
(b) 2012/2013 represent the initial years for Federal RPS/RES mandates as currently proposed by several draft bills before Congress. Further, 2013 would represent the initial year after the likely expiration of Production Tax Credits (PTC) for, particularly, wind resources. Establishment of a federal renewables standard would likely eliminate further extension of such PTC opportunities.

AEP System - SPP Zone

Potential Renewables Profile to Achieve a System-Wide 10% Target by 2020, and 15% by 2030 [a]
as well as Known or Emerging State-Specific Mandates
2010 IRP

PSO

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	303	0	9.4%
2010	0	402	0	11.8%
2011	0	591	0	14.0%
2012	0	691	0	16.6%
2013 (b)	0	691	0	15.7%
2014	0	691	0	15.5%
2015	0	691	0	15.5%
2016	0	691	0	15.4%
2017	0	791	0	17.6%
2018	0	791	0	17.5%
2019	0	791	0	17.4%
2020	0	941	0	20.6%
2021	0	941	0	20.4%
2022	0	941	0	20.2%
2023	0	1,041	0	22.3%
2024	0	1,041	0	22.0%
2025	0	1,041	0	21.8%
2026	8	1,141	0	23.6%
2027	9	1,141	0	23.6%
2028	22	1,141	0	23.5%
2029	22	1,341	0	27.3%
2030	38	1,341	0	27.3%

SWEPCO

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	31	0	0.6%
2010	0	111	0	2.4%
2011	0	111	0	2.3%
2012	0	111	0	2.2%
2013 (b)	0	111	0	2.2%
2014	0	111	0	2.2%
2015	25	311	0	6.5%
2016	25	611	0	10.6%
2017	25	611	0	12.4%
2018	25	611	0	12.3%
2019	25	611	0	12.2%
2020	25	761	0	15.0%
2021	25	861	0	16.6%
2022	25	961	0	18.5%
2023	25	961	0	18.3%
2024	25	1,061	0	20.0%
2025	25	1,161	0	21.7%
2026	34	1,161	0	21.5%
2027	34	1,261	0	23.1%
2028	47	1,261	0	23.8%
2029	47	1,261	0	22.8%
2030	83	1,361	0	24.4%

AEP-SPP

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	424	0	4.9%
2010	0	602	0	7.0%
2011	0	701	0	7.6%
2012	0	801	0	8.7%
2013 (b)	0	801	0	8.6%
2014	0	801	0	8.6%
2015	25	1,001	0	10.8%
2016	25	1,201	0	12.8%
2017	25	1,401	0	14.9%
2018	25	1,401	0	14.8%
2019	25	1,401	0	14.6%
2020	25	1,701	0	17.6%
2021	25	1,801	0	18.5%
2022	25	1,901	0	19.3%
2023	25	2,001	0	20.2%
2024	25	2,101	0	21.0%
2025	25	2,201	0	21.7%
2026	44	2,301	0	22.8%
2027	44	2,401	0	23.4%
2028	69	2,401	0	23.3%
2029	69	2,501	0	24.9%
2030	100	2,701	0	25.8%

(a) Data EXCLUDES:
- AEP-Texas Central Co. & AEP-Texas North Co. as current and potential future state/federal RPS would be applicable to LSEs only.
- Conventional (run-of-river) hydro energy as a renewable source as it has been excluded from certain state and proposed federal RPS criteria... Should hydro be ultimately included, it would contribute roughly 1% to the AEP System target by 2020

(b) 2012/2013 represent the initial years for Federal RPS/RES mandates as currently proposed by several draft bills before Congress. Further, 2013 would represent the initial year after the likely expiration of Production Tax Credits (PTC) for, particularly, wind resources. The notion being that establishment of a Federal renewables standard would likely eliminate further extension of such PTC opportunities.

AEP-System

Year	Solar Nameplate (MW)	Wind Nameplate (MW)	Biomass Equivalent (MW)	Energy as % of Sales
2009	0	400	0	1.4%
2010	0	1,120	0	2.9%
2011	20	1,327	44	3.5%
2012	31	1,527	44	3.9%
2013	41	1,627	44	4.1%
2014	67	1,927	94	5.0%
2015	119	2,627	94	6.6%
2016	145	2,977	50	7.4%
2017	171	3,327	50	8.3%
2018	197	3,377	150	8.9%
2019	223	3,477	150	9.1%
2020	250	3,927	150	10.2%
2021	281	4,127	200	10.0%
2022	326	4,327	200	11.4%
2023	326	4,627	300	12.0%
2024	370	4,877	300	13.0%
2025	370	5,127	300	13.6%
2026	408	5,377	300	14.0%
2027	408	5,627	350	14.7%
2028	458	5,727	350	14.9%
2029	458	6,027	350	15.2%
2030	520	6,027	350	15.4%

AMERICAN ELECTRIC POWER

Appendix F, Figure 1, Internal Demand by Company

APPALACHIAN POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	6,887	7,008	6,102	5,236	4,677	5,554	5,567	6,005	5,284	5,154	5,750	6,461	6,005	7,008
2011	7,087	7,220	6,212	5,290	4,733	5,670	5,587	6,041	5,374	5,187	5,828	6,587	6,041	7,220
2012	7,465	7,584	6,726	5,625	5,131	6,070	6,021	6,486	5,737	5,542	6,170	6,954	6,486	7,584
2013	7,542	7,662	6,851	5,718	5,197	6,163	6,112	6,589	5,827	5,616	6,272	7,074	6,589	7,662
2014	7,603	7,726	6,978	5,789	5,235	6,240	6,183	6,671	5,897	5,656	6,387	7,191	6,671	7,726
2015	7,658	7,785	7,097	5,851	5,259	6,301	6,238	6,737	5,949	5,687	6,447	7,304	6,737	7,785
2016	7,673	7,803	6,912	5,860	5,283	6,329	6,287	6,768	5,978	5,695	6,481	7,312	6,768	7,803
2017	7,710	7,829	7,126	5,906	5,377	6,390	6,322	6,822	6,025	5,791	6,524	7,382	6,822	7,829
2018	7,762	7,879	7,174	5,949	5,417	6,443	6,378	6,882	6,080	5,827	6,554	7,427	6,882	7,879
2019	7,813	7,931	7,224	5,993	5,463	6,501	6,438	6,947	6,141	5,866	6,593	7,470	6,947	7,931
2020	7,842	7,955	7,247	6,011	5,488	6,541	6,480	6,992	6,183	5,889	6,620	7,493	6,992	7,955
2021	7,926	8,041	7,127	6,077	5,554	6,618	6,559	7,077	6,260	5,949	6,690	7,564	7,077	8,041
2022	7,982	8,097	7,181	6,121	5,605	6,677	6,619	7,143	6,320	5,989	6,738	7,614	7,143	8,097
2023	8,008	8,109	7,383	6,185	5,696	6,737	6,673	7,197	6,357	6,085	6,774	7,673	7,197	8,109
2024	8,044	8,147	7,418	6,200	5,725	6,785	6,722	7,250	6,415	6,108	6,800	7,699	7,250	8,147
2025	8,130	8,234	7,500	6,269	5,789	6,866	6,804	7,339	6,496	6,169	6,875	7,776	7,339	8,234
2026	8,185	8,296	7,555	6,308	5,835	6,926	6,866	7,406	6,558	6,207	6,925	7,822	7,406	8,296
2027	8,247	8,359	7,420	6,352	5,889	6,992	6,932	7,479	6,622	6,250	6,975	7,874	7,479	8,359
2028	8,288	8,402	7,456	6,363	5,931	7,042	6,984	7,534	6,675	6,271	7,025	7,904	7,534	8,402
2029	8,333	8,441	7,677	6,467	6,028	7,119	7,055	7,606	6,735	6,388	7,046	7,987	7,606	8,441
2030	8,398	8,510	7,740	6,511	6,080	7,187	7,123	7,681	6,802	6,430	7,106	8,046	7,681	8,510
2031	8,466	8,579	7,807	6,557	6,133	7,255	7,192	7,756	6,872	6,478	7,163	8,103	7,756	8,579
2032	8,508	8,627	7,649	6,588	6,173	7,309	7,248	7,818	6,927	6,504	7,221	8,135	7,818	8,627
2033	8,604	8,726	7,741	6,635	6,247	7,399	7,338	7,915	7,015	6,567	7,310	8,222	7,915	8,726
2034	8,641	8,751	7,951	6,746	6,346	7,472	7,403	7,983	7,070	6,679	7,397	8,291	7,983	8,751
2035	8,720	8,834	8,024	6,798	6,407	7,550	7,483	8,068	7,149	6,728	7,374	8,358	8,068	8,834
2036	8,745	8,864	8,056	6,798	6,441	7,605	7,537	8,130	7,204	6,753	7,422	8,381	8,130	8,864
2037	8,873	8,995	8,174	6,883	6,524	7,708	7,642	8,243	7,305	6,831	7,534	8,492	8,243	8,995
2038	8,955	9,079	8,051	6,935	6,593	7,793	7,726	8,334	7,390	6,888	7,614	8,566	8,334	9,079
2039	9,036	9,169	8,132	6,985	6,661	7,875	7,810	8,425	7,471	6,943	7,690	8,639	8,425	9,169

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo. WPCo load moved from OPCo to APCo 1/2012.

COLUMBUS SOUTHERN POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	3,422	3,390	3,101	2,766	3,517	3,724	4,139	4,273	3,719	2,958	3,069	3,331	4,273	3,422
2011	3,395	3,363	3,097	2,763	3,527	3,736	4,152	4,291	3,743	2,972	3,078	3,337	4,291	3,395
2012	3,426	3,392	3,212	2,774	3,577	3,783	4,196	4,333	3,783	2,992	3,210	3,358	4,333	3,426
2013	3,474	3,444	3,268	2,827	3,636	3,842	4,260	4,400	3,844	3,036	3,060	3,402	4,400	3,474
2014	3,497	3,477	3,294	2,853	3,671	3,874	4,295	4,438	3,873	3,056	3,076	3,424	4,438	3,497
2015	3,500	3,488	3,305	2,867	3,693	3,893	4,315	4,463	3,901	3,071	3,087	3,442	4,463	3,500
2016	3,499	3,494	3,214	2,877	3,707	3,896	4,326	4,471	3,914	3,074	3,209	3,442	4,471	3,499
2017	3,511	3,503	3,309	2,875	3,738	3,926	4,357	4,499	3,946	3,088	3,335	3,464	4,499	3,511
2018	3,518	3,521	3,324	2,890	3,762	3,949	4,378	4,521	3,971	3,097	3,345	3,472	4,521	3,521
2019	3,531	3,544	3,343	2,908	3,785	3,971	4,397	4,544	3,993	3,108	3,148	3,484	4,544	3,544
2020	3,533	3,546	3,347	2,919	3,803	3,977	4,406	4,554	4,002	3,112	3,143	3,486	4,554	3,546
2021	3,574	3,599	3,283	2,951	3,838	4,007	4,438	4,578	4,023	3,121	3,270	3,492	4,578	3,599
2022	3,589	3,616	3,303	2,968	3,857	4,027	4,465	4,603	4,044	3,132	3,279	3,509	4,603	3,616
2023	3,600	3,610	3,392	2,960	3,876	4,050	4,491	4,628	4,067	3,144	3,400	3,630	4,628	3,610
2024	3,610	3,613	3,406	2,968	3,896	4,072	4,510	4,636	4,085	3,152	3,199	3,539	4,636	3,613
2025	3,640	3,656	3,434	2,994	3,933	4,104	4,551	4,682	4,118	3,176	3,221	3,568	4,682	3,656
2026	3,664	3,683	3,454	3,015	3,966	4,133	4,588	4,719	4,147	3,196	3,235	3,591	4,719	3,683
2027	3,689	3,708	3,372	3,036	3,998	4,164	4,629	4,759	4,180	3,218	3,359	3,615	4,759	3,708
2028	3,706	3,718	3,394	3,054	4,021	4,192	4,663	4,792	4,211	3,233	3,374	3,639	4,792	3,718
2029	3,736	3,741	3,506	3,052	4,058	4,235	4,710	4,841	4,250	3,269	3,515	3,678	4,841	3,741
2030	3,763	3,769	3,533	3,076	4,094	4,272	4,750	4,887	4,284	3,285	3,340	3,703	4,887	3,769
2031	3,795	3,804	3,568	3,104	4,139	4,311	4,800	4,940	4,325	3,257	3,357	3,735	4,940	3,804
2032	3,821	3,824	3,475	3,129	4,178	4,345	4,845	4,984	4,360	3,285	3,473	3,759	4,984	3,824
2033	3,867	3,880	3,521	3,170	4,229	4,398	4,910	5,048	4,414	3,323	3,508	3,808	5,048	3,880
2034	3,899	3,891	3,639	3,208	4,266	4,446	4,954	5,102	4,460	3,364	3,656	3,850	5,102	3,899
2035	3,938	3,934	3,676	3,242	4,316	4,497	5,020	5,163	4,512	3,398	3,689	3,890	5,163	3,938
2036	3,961	3,945	3,834	3,268	4,362	4,537	5,067	5,216	4,548	3,425	3,516	3,913	5,216	3,961
2037	4,022	4,023	3,755	3,315	4,431	4,599	5,144	5,296	4,613	3,473	3,559	3,972	5,296	4,023
2038	4,069	4,068	3,678	3,354	4,486	4,656	5,212	5,365	4,670	3,514	3,679	4,017	5,365	4,069
2039	4,114	4,120	3,724	3,397	4,541	4,713	5,283	5,434	4,729	3,555	3,715	4,066	5,434	4,120

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 2, Internal Demand by Company

INDIANA MICHIGAN POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	3,817	3,694	3,421	3,237	3,222	4,046	4,436	4,417	3,831	3,233	3,257	3,548	4,436	3,817
2011	3,827	3,705	3,432	3,253	3,235	4,085	4,459	4,439	3,851	3,248	3,263	3,556	4,459	3,827
2012	3,908	3,784	3,560	3,310	3,332	4,184	4,558	4,538	3,943	3,310	3,372	3,623	4,558	3,908
2013	3,975	3,850	3,822	3,375	3,392	4,234	4,634	4,614	4,012	3,368	3,414	3,675	4,634	3,975
2014	3,989	3,865	3,838	3,396	3,409	4,247	4,642	4,625	4,027	3,400	3,420	3,707	4,642	3,989
2015	4,000	3,876	3,650	3,412	3,422	4,260	4,656	4,640	4,042	3,421	3,425	3,725	4,656	4,000
2016	3,998	3,877	3,597	3,422	3,424	4,282	4,656	4,642	4,047	3,438	3,427	3,733	4,656	3,998
2017	4,021	3,898	3,669	3,422	3,458	4,292	4,684	4,672	4,076	3,422	3,479	3,685	4,684	4,021
2018	4,040	3,919	3,690	3,447	3,487	4,314	4,707	4,696	4,099	3,447	3,491	3,794	4,707	4,040
2019	4,062	3,941	3,710	3,471	3,509	4,338	4,731	4,720	4,124	3,473	3,505	3,711	4,731	4,062
2020	4,071	3,951	3,721	3,475	3,518	4,352	4,746	4,736	4,139	3,489	3,502	3,719	4,746	4,071
2021	4,107	3,986	3,701	3,511	3,547	4,392	4,790	4,780	4,178	3,523	3,533	3,752	4,790	4,107
2022	4,130	4,009	3,722	3,537	3,568	4,420	4,823	4,812	4,206	3,548	3,554	3,773	4,823	4,130
2023	4,147	4,024	3,788	3,542	3,595	4,450	4,855	4,843	4,232	3,558	3,598	3,782	4,855	4,147
2024	4,157	4,033	3,798	3,552	3,610	4,467	4,876	4,864	4,250	3,574	3,596	3,806	4,876	4,157
2025	4,194	4,071	3,833	3,581	3,642	4,510	4,924	4,911	4,291	3,609	3,622	3,840	4,924	4,194
2026	4,219	4,094	3,857	3,609	3,663	4,541	4,960	4,946	4,321	3,634	3,638	3,863	4,960	4,219
2027	4,242	4,116	3,823	3,634	3,683	4,571	4,994	4,980	4,350	3,657	3,658	3,884	4,994	4,242
2028	4,259	4,133	3,838	3,661	3,695	4,593	5,020	5,008	4,373	3,678	3,673	3,885	5,020	4,259
2029	4,288	4,160	3,918	3,663	3,741	4,638	5,067	5,051	4,410	3,699	3,723	3,934	5,067	4,288
2030	4,315	4,188	3,943	3,685	3,765	4,670	5,106	5,090	4,443	3,727	3,740	3,959	5,106	4,315
2031	4,344	4,215	3,971	3,715	3,789	4,705	5,146	5,130	4,478	3,755	3,759	3,985	5,146	4,344
2032	4,358	4,230	3,928	3,741	3,801	4,728	5,173	5,158	4,501	3,775	3,784	3,999	5,173	4,358
2033	4,404	4,274	3,951	3,785	3,838	4,780	5,230	5,214	4,550	3,817	3,804	4,041	5,230	4,404
2034	4,431	4,298	4,049	3,787	3,876	4,822	5,277	5,259	4,587	3,836	3,861	4,058	5,277	4,431
2035	4,465	4,332	4,080	3,813	3,913	4,863	5,323	5,306	4,627	3,869	3,884	4,104	5,323	4,465
2036	4,476	4,344	4,102	3,839	3,926	4,887	5,352	5,336	4,652	3,891	3,884	4,117	5,352	4,476
2037	4,526	4,392	4,138	3,885	3,962	4,940	5,411	5,393	4,701	3,932	3,917	4,161	5,411	4,526
2038	4,556	4,422	4,084	3,917	3,989	4,978	5,455	5,437	4,739	3,962	3,943	4,189	5,455	4,556
2039	4,584	4,450	4,119	3,946	4,011	5,013	5,496	5,478	4,773	3,991	3,967	4,215	5,496	4,584

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

KENTUCKY POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	1,403	1,483	1,270	1,103	977	1,086	1,168	1,260	1,032	1,009	1,185	1,374	1,260	1,483
2011	1,467	1,545	1,289	1,111	982	1,106	1,164	1,257	1,047	1,011	1,196	1,395	1,257	1,545
2012	1,471	1,543	1,341	1,120	997	1,122	1,169	1,262	1,056	1,021	1,212	1,416	1,262	1,543
2013	1,481	1,548	1,372	1,138	1,018	1,144	1,173	1,267	1,078	1,031	1,231	1,448	1,267	1,548
2014	1,492	1,549	1,411	1,157	1,023	1,160	1,175	1,272	1,084	1,036	1,258	1,492	1,272	1,549
2015	1,507	1,554	1,458	1,181	1,018	1,168	1,177	1,276	1,089	1,040	1,283	1,542	1,276	1,554
2016	1,506	1,555	1,402	1,184	1,011	1,168	1,177	1,277	1,090	1,040	1,281	1,541	1,277	1,555
2017	1,510	1,559	1,462	1,180	1,021	1,174	1,180	1,277	1,097	1,053	1,340	1,551	1,277	1,559
2018	1,517	1,566	1,469	1,187	1,026	1,179	1,186	1,283	1,103	1,056	1,306	1,557	1,283	1,566
2019	1,517	1,568	1,474	1,194	1,043	1,184	1,193	1,290	1,110	1,061	1,305	1,558	1,290	1,568
2020	1,512	1,565	1,473	1,196	1,039	1,185	1,196	1,294	1,107	1,062	1,299	1,555	1,294	1,565
2021	1,520	1,575	1,422	1,207	1,043	1,195	1,208	1,305	1,117	1,071	1,304	1,562	1,305	1,575
2022	1,524	1,580	1,430	1,215	1,046	1,203	1,214	1,315	1,126	1,077	1,308	1,567	1,315	1,580
2023	1,522	1,580	1,488	1,213	1,062	1,210	1,218	1,316	1,134	1,091	1,378	1,573	1,316	1,580
2024	1,522	1,582	1,491	1,216	1,075	1,215	1,225	1,323	1,141	1,093	1,325	1,574	1,323	1,582
2025	1,533	1,593	1,503	1,229	1,081	1,226	1,237	1,336	1,146	1,102	1,334	1,584	1,336	1,593
2026	1,538	1,601	1,510	1,237	1,085	1,236	1,246	1,348	1,155	1,109	1,338	1,590	1,348	1,601
2027	1,545	1,609	1,458	1,245	1,090	1,244	1,256	1,359	1,165	1,115	1,342	1,596	1,359	1,609
2028	1,546	1,613	1,463	1,250	1,089	1,250	1,264	1,367	1,173	1,119	1,342	1,599	1,367	1,613
2029	1,550	1,617	1,527	1,258	1,113	1,261	1,271	1,372	1,184	1,137	1,363	1,611	1,372	1,617
2030	1,557	1,626	1,536	1,264	1,126	1,270	1,281	1,383	1,194	1,142	1,368	1,618	1,383	1,626
2031	1,564	1,634	1,545	1,272	1,131	1,279	1,291	1,395	1,196	1,149	1,373	1,625	1,395	1,634
2032	1,567	1,639	1,487	1,276	1,129	1,286	1,299	1,403	1,204	1,153	1,375	1,627	1,403	1,639
2033	1,579	1,651	1,500	1,287	1,136	1,297	1,312	1,417	1,216	1,162	1,385	1,639	1,417	1,651
2034	1,579	1,653	1,564	1,294	1,157	1,307	1,317	1,420	1,227	1,179	1,473	1,648	1,420	1,653
2035	1,587	1,663	1,574	1,303	1,166	1,318	1,328	1,433	1,238	1,185	1,410	1,656	1,433	1,663
2036	1,583	1,660	1,631	1,301	1,171	1,321	1,334	1,439	1,238	1,188	1,403	1,653	1,439	1,660
2037	1,602	1,682	1,593	1,318	1,180	1,338	1,350	1,457	1,251	1,199	1,420	1,671	1,457	1,682
2038	1,610	1,692	1,538	1,327	1,188	1,347	1,362	1,471	1,263	1,207	1,428	1,681	1,471	1,692
2039	1,619	1,703	1,550	1,338	1,192	1,357	1,374	1,484	1,277	1,215	1,438	1,690	1,484	1,703

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 3, Internal Demand by Company

OHIO POWER COMPANY
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC		
2010	4,786	4,650	4,375	3,950	4,116	4,709	5,124	5,022	4,656	3,815	4,241	4,332	5,124	4,786
2011	4,825	4,603	4,425	3,996	4,148	4,745	5,161	5,059	4,696	3,841	4,280	4,381	5,161	4,826
2012	4,487	4,268	4,186	3,728	3,901	4,466	4,846	4,744	4,410	3,614	4,076	4,116	4,846	4,487
2013	4,552	4,332	4,254	3,795	3,958	4,528	4,907	4,805	4,470	3,677	3,882	4,174	4,907	4,552
2014	4,588	4,370	4,291	3,835	3,992	4,584	4,942	4,841	4,506	3,709	3,911	4,204	4,942	4,588
2015	4,609	4,395	4,319	3,868	4,019	4,595	4,972	4,871	4,540	3,737	3,938	4,235	4,972	4,609
2016	4,618	4,407	4,289	3,888	4,034	4,609	4,983	4,882	4,553	3,743	4,188	4,237	4,983	4,618
2017	4,641	4,428	4,349	3,891	4,062	4,640	5,011	4,908	4,580	3,785	4,282	4,265	5,011	4,641
2018	4,655	4,443	4,366	3,911	4,080	4,659	5,029	4,926	4,599	3,797	4,270	4,278	5,029	4,655
2019	4,675	4,466	4,388	3,936	4,102	4,685	5,052	4,952	4,624	3,812	4,016	4,295	5,052	4,675
2020	4,676	4,468	4,393	3,949	4,110	4,691	5,057	4,957	4,631	3,814	4,013	4,295	5,057	4,676
2021	4,715	4,511	4,387	3,988	4,141	4,724	5,091	4,989	4,661	3,835	4,287	4,316	5,091	4,715
2022	4,736	4,533	4,410	4,011	4,161	4,747	5,116	5,014	4,684	3,849	4,302	4,336	5,116	4,736
2023	4,750	4,541	4,460	4,004	4,180	4,772	5,140	5,036	4,706	3,883	4,389	4,354	5,140	4,750
2024	4,753	4,541	4,465	4,011	4,187	4,781	5,150	5,048	4,715	3,882	4,083	4,355	5,150	4,753
2025	4,784	4,576	4,496	4,042	4,216	4,814	5,188	5,086	4,747	3,905	4,106	4,384	5,188	4,784
2026	4,806	4,598	4,517	4,064	4,238	4,838	5,217	5,113	4,773	3,918	4,118	4,403	5,217	4,806
2027	4,829	4,621	4,494	4,088	4,260	4,865	5,249	5,143	4,800	3,934	4,394	4,422	5,249	4,829
2028	4,843	4,631	4,509	4,107	4,276	4,884	5,272	5,165	4,821	3,939	4,402	4,436	5,272	4,843
2029	4,871	4,656	4,572	4,111	4,305	4,921	5,310	5,200	4,853	3,984	4,477	4,468	5,310	4,871
2030	4,893	4,676	4,595	4,132	4,327	4,948	5,338	5,231	4,879	3,999	4,206	4,488	5,338	4,893
2031	4,919	4,703	4,621	4,157	4,353	4,977	5,372	5,263	4,908	4,017	4,222	4,510	5,372	4,919
2032	4,928	4,709	4,585	4,170	4,368	4,993	5,393	5,283	4,925	4,020	4,491	4,518	5,393	4,928
2033	4,968	4,753	4,624	4,210	4,402	5,035	5,440	5,328	4,966	4,048	4,523	4,556	5,440	4,968
2034	4,992	4,770	4,682	4,210	4,427	5,068	5,474	5,360	4,996	4,088	4,620	4,582	5,474	4,992
2035	5,020	4,796	4,711	4,236	4,453	5,101	5,510	5,395	5,027	4,106	4,615	4,608	5,510	5,020
2036	5,027	4,801	4,813	4,251	4,472	5,121	5,535	5,420	5,047	4,115	4,321	4,614	5,535	5,027
2037	5,082	4,858	4,773	4,299	4,516	5,171	5,591	5,475	5,097	4,152	4,360	4,663	5,591	5,082
2038	5,122	4,898	4,763	4,336	4,553	5,215	5,642	5,523	5,141	4,188	4,669	4,698	5,642	5,122
2039	5,155	4,931	4,797	4,369	4,585	5,254	5,677	5,564	5,180	4,212	4,697	4,730	5,677	5,155

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

AEP SYSTEM - (EAST)
MONTHLY PEAK INTERNAL DEMAND - (MW) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2039

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Summer	Winter
2010	20,159	20,044	17,552	16,199	16,053	18,561	20,383	20,821	18,416	15,664	17,143	18,724	20,821	20,159
2011	20,437	20,367	17,725	16,322	16,167	18,732	20,473	20,930	18,599	15,758	17,258	18,939	20,930	20,437
2012	20,581	20,495	18,870	16,468	16,466	19,014	20,736	21,191	18,843	16,050	17,695	19,188	21,191	20,581
2013	20,845	20,764	19,206	16,753	16,706	19,302	21,025	21,495	19,136	16,286	17,506	19,485	21,495	20,845
2014	20,990	20,916	19,446	16,927	16,821	19,455	21,176	21,663	19,295	16,391	17,685	19,711	21,663	20,990
2015	21,095	21,026	19,655	17,069	16,892	19,564	21,291	21,800	19,421	16,481	17,839	19,930	21,800	21,095
2016	21,118	21,064	18,644	17,117	16,946	19,612	21,341	21,852	19,482	16,497	18,073	19,936	21,852	21,118
2017	21,193	21,134	19,727	17,164	17,164	19,770	21,477	21,984	19,607	16,728	18,683	20,096	21,984	21,193
2018	21,294	21,245	19,835	17,275	17,261	19,886	21,597	22,111	19,735	16,806	18,533	20,189	22,111	21,294
2019	21,403	21,370	19,952	17,391	17,368	20,015	21,729	22,258	19,874	16,894	18,211	20,273	22,258	21,403
2020	21,440	21,403	19,998	17,447	17,418	20,078	21,799	22,338	19,949	16,933	18,239	20,304	22,338	21,440
2021	21,851	21,631	19,168	17,627	17,584	20,259	21,996	22,533	20,126	17,056	18,630	20,434	22,533	21,651
2022	21,769	21,753	19,292	17,739	17,699	20,390	22,151	22,690	20,266	17,140	18,727	20,541	22,690	21,769
2023	21,806	21,771	20,310	17,785	17,891	20,538	22,286	22,819	20,377	17,345	19,323	20,670	22,819	21,806
2024	21,867	21,826	20,378	17,832	17,948	20,637	22,391	22,926	20,478	17,376	18,623	20,707	22,926	21,867
2025	22,062	22,037	20,568	18,006	18,108	20,828	22,613	23,159	20,676	17,514	18,781	20,880	23,159	22,062
2026	22,193	22,181	20,691	18,118	18,229	20,977	22,786	23,337	20,836	17,603	18,882	20,988	23,337	22,193
2027	22,334	22,321	19,807	18,237	18,362	21,131	22,967	23,523	21,000	17,697	19,314	21,103	23,523	22,334
2028	22,423	22,406	19,892	18,304	18,460	21,251	23,113	23,669	21,135	17,764	19,397	21,181	23,869	22,423
2029	22,532	22,509	20,982	18,443	18,693	21,463	23,317	23,868	21,300	18,013	19,816	21,377	23,868	22,532
2030	22,680	22,666	21,129	18,558	18,825	21,630	23,504	24,068	21,470	18,106	19,340	21,508	24,068	22,680
2031	22,844	22,832	21,290	18,690	18,971	21,803	23,705	24,282	21,653	18,194	19,458	21,644	24,282	22,844
2032	22,938	22,926	20,342	18,760	19,075	21,929	23,863	24,442	21,792	18,260	19,937	21,715	24,442	22,938
2033	23,177	23,180	20,684	18,950	19,279	22,169	24,136	24,718	22,038	18,425	20,137	21,933	24,718	23,180
2034	23,267	23,242	21,650	19,096	19,515	22,378	24,335	24,913	22,203	18,662	20,795	22,106	24,913	23,267
2035	23,456	23,439	21,836	19,243	19,680	22,580	24,564	25,156	22,417	18,797	20,705	22,289	25,156	23,456
2036	23,515	23,492	22,106	19,286	19,779	22,716	24,725	25,330	22,558	18,862	20,095	22,322	25,330	23,515
2037	23,834	23,831	22,198	19,526	20,012	22,989	25,036	25,653	22,840	19,066	20,348	22,594	25,653	23,834
2038	24,040	24,037	21,327	19,686	20,206	23,210	25,293	25,918	23,073	19,233	20,960	22,776	25,918	24,040
2039	24,237	24,253	21,520	19,841	20,390	23,425	25,544	26,172	23,298	19,381	21,132	22,966	26,172	24,253

Notes: Load Forecast per J. M. Harris (04/26/10). Demands do not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 4, Internal Energy by Company

APPALACHIAN POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	3,825	3,239	3,097	2,671	2,629	2,847	3,064	3,100	2,722	2,748	2,974	3,529	36,444
2011	3,851	3,249	3,096	2,652	2,624	2,860	3,078	3,127	2,721	2,736	2,967	3,648	36,508
2012	4,110	3,593	3,326	2,864	2,857	3,088	3,337	3,386	2,937	2,972	3,181	3,767	39,418
2013	4,172	3,527	3,368	2,912	2,898	3,130	3,396	3,431	2,989	3,014	3,217	3,827	39,881
2014	4,218	3,564	3,404	2,933	2,911	3,169	3,434	3,461	3,025	3,031	3,235	3,873	40,259
2015	4,248	3,581	3,433	2,944	2,915	3,202	3,461	3,490	3,045	3,033	3,255	3,906	40,523
2016	4,249	3,717	3,434	2,945	2,935	3,217	3,481	3,522	3,059	3,040	3,284	3,912	40,776
2017	4,300	3,831	3,469	2,970	2,975	3,248	3,496	3,559	3,083	3,081	3,312	3,938	41,062
2018	4,331	3,657	3,490	3,002	3,004	3,289	3,535	3,589	3,104	3,116	3,334	3,965	41,396
2019	4,364	3,685	3,512	3,039	3,033	3,293	3,576	3,613	3,140	3,148	3,354	4,002	41,760
2020	4,382	3,817	3,540	3,058	3,037	3,330	3,599	3,630	3,171	3,162	3,370	4,028	42,126

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo. WPCo load moved from OPCo to APCo 1/2012.

COLUMBUS SOUTHERN POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	2,027	1,788	1,839	1,618	1,685	1,880	2,081	2,056	1,736	1,692	1,743	1,985	22,130
2011	2,019	1,779	1,838	1,611	1,691	1,883	2,080	2,070	1,744	1,702	1,745	1,988	22,147
2012	2,049	1,863	1,868	1,633	1,719	1,898	2,110	2,092	1,761	1,732	1,747	1,991	22,453
2013	2,081	1,830	1,898	1,666	1,746	1,922	2,149	2,116	1,784	1,760	1,763	2,028	22,739
2014	2,094	1,844	1,918	1,679	1,752	1,941	2,165	2,125	1,802	1,772	1,764	2,048	22,902
2015	2,091	1,847	1,932	1,684	1,762	1,963	2,173	2,134	1,811	1,775	1,775	2,060	22,988
2016	2,086	1,909	1,906	1,681	1,759	1,955	2,162	2,150	1,812	1,773	1,816	2,059	23,068
2017	2,107	1,861	1,924	1,689	1,776	1,967	2,177	2,161	1,818	1,790	1,819	2,064	23,153
2018	2,113	1,869	1,930	1,701	1,784	1,968	2,190	2,168	1,820	1,802	1,819	2,071	23,235
2019	2,120	1,877	1,939	1,715	1,790	1,970	2,205	2,169	1,832	1,809	1,817	2,084	23,329
2020	2,121	1,933	1,956	1,719	1,782	1,983	2,208	2,167	1,840	1,807	1,810	2,091	23,417

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo OR estimated Ohio Choice customer load migration.

INDIANA MICHIGAN POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	2,244	2,038	2,094	1,897	1,918	2,116	2,314	2,327	2,030	1,973	1,976	2,229	25,157
2011	2,260	2,044	2,104	1,894	1,935	2,125	2,313	2,348	2,038	1,982	1,982	2,228	25,251
2012	2,322	2,166	2,148	1,943	1,999	2,167	2,381	2,407	2,070	2,058	2,023	2,259	25,941
2013	2,363	2,128	2,177	1,988	2,033	2,194	2,432	2,436	2,117	2,092	2,045	2,305	26,308
2014	2,375	2,140	2,192	2,002	2,036	2,216	2,443	2,437	2,141	2,106	2,046	2,328	26,458
2015	2,373	2,147	2,212	2,010	2,033	2,235	2,450	2,446	2,151	2,104	2,062	2,336	26,559
2016	2,364	2,223	2,215	2,001	2,048	2,239	2,430	2,473	2,154	2,098	2,086	2,333	26,683
2017	2,404	2,166	2,236	2,009	2,078	2,266	2,449	2,493	2,182	2,128	2,101	2,333	26,815
2018	2,419	2,179	2,240	2,033	2,094	2,259	2,475	2,507	2,185	2,155	2,111	2,345	26,982
2019	2,435	2,192	2,245	2,058	2,107	2,262	2,501	2,509	2,191	2,170	2,113	2,369	27,153
2020	2,440	2,264	2,266	2,066	2,090	2,292	2,509	2,506	2,211	2,165	2,118	2,388	27,311

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

Appendix F, Figure 5, Internal Energy by Company

KENTUCKY POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	795	690	670	582	572	599	623	657	569	570	636	753	7,715
2011	797	690	668	578	570	601	625	660	568	566	633	752	7,708
2012	800	713	667	577	570	602	628	663	568	566	632	754	7,740
2013	809	698	672	578	570	606	635	669	572	566	634	762	7,771
2014	819	705	678	577	567	609	637	670	572	563	635	771	7,802
2015	828	711	683	574	563	609	638	672	571	558	638	778	7,823
2016	827	733	681	574	565	611	638	675	573	559	640	778	7,854
2017	833	715	686	578	570	615	643	680	577	564	643	782	7,886
2018	837	718	688	582	574	618	647	683	580	568	645	785	7,926
2019	840	721	692	587	578	622	653	687	585	573	648	788	7,974
2020	840	743	695	589	580	626	656	689	588	574	649	790	8,019

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo.

OHIO POWER COMPANY
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	2,798	2,513	2,631	2,327	2,341	2,513	2,722	2,747	2,411	2,364	2,450	2,691	30,508
2011	2,837	2,538	2,664	2,335	2,375	2,533	2,727	2,784	2,428	2,388	2,471	2,704	30,785
2012	2,650	2,441	2,470	2,175	2,229	2,351	2,567	2,601	2,241	2,256	2,281	2,496	28,758
2013	2,687	2,387	2,496	2,222	2,259	2,371	2,616	2,620	2,286	2,280	2,293	2,539	29,066
2014	2,702	2,404	2,522	2,242	2,263	2,405	2,636	2,624	2,321	2,306	2,292	2,568	29,286
2015	2,698	2,415	2,554	2,256	2,262	2,435	2,649	2,642	2,338	2,308	2,316	2,586	29,457
2016	2,687	2,504	2,545	2,245	2,285	2,442	2,624	2,680	2,341	2,289	2,363	2,577	29,592
2017	2,728	2,433	2,564	2,247	2,315	2,455	2,641	2,696	2,338	2,330	2,369	2,586	29,682
2018	2,738	2,440	2,560	2,269	2,326	2,447	2,665	2,702	2,333	2,353	2,367	2,574	29,772
2019	2,749	2,450	2,561	2,294	2,331	2,446	2,693	2,697	2,357	2,363	2,356	2,597	29,895
2020	2,745	2,522	2,589	2,297	2,302	2,478	2,693	2,685	2,377	2,347	2,348	2,612	29,996

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo OR estimated Ohio Choice customer load migration.
WPCo load moved from OPCo to APCo 1/2012.

AEP SYSTEM - (EAST)
MONTHLY ENERGY REQUIREMENT - (GWH) W/O EMBEDDED DSM
JANUARY 2010 - DECEMBER 2020

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
2010	11,689	10,268	10,331	9,096	9,144	9,956	10,603	10,887	9,468	9,347	9,779	11,187	121,954
2011	11,763	10,300	10,369	9,069	9,198	10,003	10,823	10,990	9,499	9,372	9,799	11,217	122,399
2012	11,931	10,776	10,479	9,191	9,373	10,106	11,024	11,149	9,588	9,582	9,884	11,267	124,310
2013	12,112	10,570	10,611	9,366	9,505	10,222	11,228	11,272	9,747	9,723	9,951	11,459	125,765
2014	12,208	10,657	10,713	9,433	9,528	10,340	11,315	11,317	9,862	9,778	9,971	11,585	126,706
2015	12,237	10,711	10,814	9,469	9,525	10,436	11,371	11,384	9,917	9,778	10,044	11,664	127,349
2016	12,214	11,086	10,782	9,446	9,592	10,465	11,314	11,499	9,938	9,767	10,188	11,659	127,949
2017	12,372	10,807	10,878	9,492	9,716	10,541	11,406	11,589	9,976	9,893	10,244	11,682	128,595
2018	12,438	10,862	10,908	9,687	9,780	10,561	11,612	11,648	10,002	9,993	10,276	11,739	129,305
2019	12,507	10,925	10,949	9,693	9,840	10,592	11,627	11,676	10,105	10,063	10,288	11,839	130,104
2020	12,526	11,280	11,046	9,728	9,792	10,708	11,663	11,678	10,188	10,054	10,292	11,907	130,863

Notes: Load Forecast per J. M. Harris (04/26/10). Energy does not reflect a reduction for PJM marginal losses OR reflect mandated commission approved and incremental DSM programs for APCo, CSP, I&M, KPCo & OPCo OR estimated Ohio Choice customer load-migration.
WPCo load moved from OPCo to APCo 1/2012.

Appendix G, Figure 1, DSM by Company

APCo (Includes Wheeling and Kingsport)

	Energy Efficiency			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	193	27	193	27
2012	293	40	293	40
2013	395	55	395	55
2014	498	76	498	76
2015	603	80	603	80
2016	604	80	604	80
2017	605	79	605	79
2018	606	79	606	79
2019	606	79	606	79
2020	606	78	606	78

	IVVC			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	67	6	67	6
2015	116	25	116	25
2016	142	30	142	30
2017	167	36	167	36
2018	193	41	193	41
2019	193	41	193	41
2020	193	41	193	41

	Demand Response			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	31	0	31
2012	0	61	0	61
2013	0	107	0	107
2014	0	153	0	153
2015	0	184	0	184
2016	0	184	0	184
2017	0	184	0	184
2018	0	184	0	184
2019	0	184	0	184
2020	0	184	0	184

	Total Incremental DSM			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	193	57	193	57
2012	293	101	293	101
2013	395	162	395	162
2014	565	236	565	236
2015	719	289	719	289
2016	746	294	746	294
2017	772	298	772	298
2018	799	303	799	303
2019	799	304	799	304
2020	799	303	799	303

[illegible]

	Energy Efficiency			
	Installed		Net	
	GWh	MW	GWh	MW
2010	92	16	46	8
2011	270	47	181	30
2012	500	88	370	61
2013	765	134	572	95
2014	1,070	188	782	129
2015	1,382	243	980	162
2016	1,682	295	1,139	188
2017	1,985	348	1,259	208
2018	2,289	402	1,351	223
2019	2,901	509	1,572	260
2020	3,480	609	1,876	309

	IVVC			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	15	3	15	3
2015	28	5	28	5
2016	39	7	39	7
2017	50	9	50	9
2018	60	11	60	11
2019	60	11	60	11
2020	60	11	60	11

	Demand Response			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	24	0	24
2012	0	48	0	48
2013	0	83	0	83
2014	0	119	0	119
2015	0	143	0	143
2016	0	143	0	143
2017	0	143	0	143
2018	0	143	0	143
2019	0	143	0	143
2020	0	143	0	143

	Total Incremental DSM			
	Installed		Net	
	GWh	MW	GWh	MW
2010	92	16	46	8
2011	270	71	181	54
2012	500	135	370	109
2013	765	218	572	178
2014	1,085	310	797	251
2015	1,410	391	1,008	310
2016	1,721	445	1,178	338
2017	2,034	500	1,309	360
2018	2,349	556	1,412	378
2019	2,961	663	1,632	414
2020	3,540	763	1,936	464

[illegible]

	[illegible]			
	Installed		Net	
	GWh	MW	GWh	MW
2010	73	14	37	7
2011	217	42	145	27
2012	405	79	299	55
2013	622	132	465	86
2014	873	171	638	118
2015	1,130	221	802	148
2016	1,379	269	935	172
2017	1,632	319	1,037	192
2018	1,887	370	1,117	206
2019	2,403	471	1,305	241
2020	2,892	566	1,567	289

	[illegible]			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	31	6	31	6
2015	66	14	66	14
2016	100	21	100	21
2017	135	28	135	28
2018	170	35	170	35
2019	170	35	170	35
2020	170	35	170	35

	[illegible]			
	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	21	0	21
2012	0	43	0	43
2013	0	75	0	75
2014	0	107	0	107
2015	0	128	0	128
2016	0	128	0	128
2017	0	128	0	128
2018	0	128	0	128
2019	0	128	0	128
2020	0	128	0	128

	[illegible]			
	Installed		Net	
	GWh	MW	GWh	MW
2010	73	14	37	7
2011	217	64	145	48
2012	405	122	299	98
2013	622	196	465	161
2014	904	284	669	231
2015	1,196	363	868	290
2016	1,480	418	1,036	321
2017	1,767	475	1,172	347
2018	2,057	533	1,287	370
2019	2,572	634	1,475	405
2020	3,062	729	1,736	452

AMERICAN ELECTRIC POWER

Appendix G, Figure 2, DSM by Company

Kentucky Power

Energy Efficiency	Installed		Net	
	GWh	MW	GWh	MW
2010	2	0	1	0
2011	47	7	43	6
2012	73	10	66	10
2013	99	14	90	13
2014	126	17	114	17
2015	154	20	138	20
2016	157	20	139	20
2017	159	20	139	20
2018	161	20	139	20
2019	163	20	140	20
2020	165	20	140	20

IVVC	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	18	4	18	4
2015	30	6	30	6
2016	34	7	34	7
2017	39	8	39	8
2018	44	9	44	9
2018	44	9	44	9
2020	44	9	44	9

Demand Response	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	6	0	6
2012	0	12	0	12
2013	0	22	0	22
2014	0	31	0	31
2015	0	37	0	37
2016	0	37	0	37
2017	0	37	0	37
2018	0	37	0	37
2019	0	37	0	37
2020	0	37	0	37

Total Incremental DSM	Installed		Net	
	GWh	MW	GWh	MW
2010	2	0	1	0
2011	47	13	43	13
2012	73	22	66	22
2013	99	35	90	35
2014	144	52	132	52
2015	184	64	168	64
2016	191	65	173	65
2017	198	66	178	66
2018	205	67	183	67
2019	207	67	183	67
2020	209	67	183	67

Indiana Michigan

Energy Efficiency	Installed		Net	
	GWh	MW	GWh	MW
2010	66	8	6	2
2011	173	26	120	17
2012	321	49	238	34
2013	505	79	375	55
2014	725	111	528	75
2015	980	143	692	94
2016	1,269	180	860	113
2017	1,590	221	1,029	133
2018	1,943	266	1,194	151
2019	2,310	313	1,344	168
2020	2,344	319	1,414	176

IVVC	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	5	1	5	1
2015	13	3	13	3
2016	23	4	23	4
2017	32	6	32	6
2018	42	8	42	8
2019	42	8	42	8
2020	42	8	42	8

Demand Response	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	18	0	18
2012	0	36	0	36
2013	0	63	0	63
2014	0	90	0	90
2015	0	109	0	109
2016	0	109	0	109
2017	0	109	0	109
2018	0	109	0	109
2019	0	109	0	109
2020	0	109	0	109

Total Incremental DSM	Installed		Net	
	GWh	MW	GWh	MW
2010	66	8	8	2
2011	173	44	120	35
2012	321	86	238	70
2013	505	143	375	118
2014	730	202	533	167
2015	993	255	705	205
2016	1,292	293	883	226
2017	1,623	336	1,061	247
2018	1,985	383	1,236	268
2019	2,352	430	1,386	285
2020	2,386	435	1,456	293

AEP East

Energy Efficiency	Installed		Net	
	GWh	MW	GWh	MW
2010	233	38	91	16
2011	900	149	683	107
2012	1,592	266	1,266	200
2013	2,385	404	1,897	304
2014	3,294	563	2,560	416
2015	4,249	708	3,216	505
2016	5,091	844	3,676	573
2017	5,971	988	4,069	631
2018	6,887	1,138	4,408	680
2019	8,383	1,392	4,967	768
2020	9,487	1,593	5,602	873

IVVC	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	136	20	136	20
2015	253	63	253	63
2016	338	70	338	70
2017	423	88	423	88
2018	509	105	509	105
2019	509	106	509	106
2020	509	105	509	105

Demand Response	Installed		Net	
	GWh	MW	GWh	MW
2010	0	0	0	0
2011	0	100	0	100
2012	0	200	0	200
2013	0	350	0	350
2014	0	500	0	500
2015	0	600	0	600
2016	0	600	0	600
2017	0	600	0	600
2018	0	600	0	600
2019	0	600	0	600
2020	0	600	0	600

Total Incremental DSM	Installed		Net	
	GWh	MW	GWh	MW
2010	233	38	91	16
2011	900	249	683	207
2012	1,592	466	1,266	400
2013	2,385	754	1,897	654
2014	3,429	1,084	2,898	938
2015	4,502	1,361	3,468	1,158
2016	5,429	1,514	4,015	1,244
2017	6,394	1,676	4.493	1,319
2018	7,395	1,842	4,917	1,385
2019	8,891	2,098	5,476	1,474
2020	9,896	2,288	6,111	1,578

AMERICAN ELECTRIC POWER

Appendix H, Ohio Choice by Company

Columbus Southern Power

Ohio Customer Choice		
	GWh	SUMMER Peak MW
2010	0	0
2011	139	28
2012	326	55
2013	454	76
2014	582	98
2015	780	132
2016	1,037	172
2017	1,293	214
2018	1,550	255
2019	1,806	298
2020	2,062	341

Ohio Power

Ohio Customer Choice		
	GWh	SUMMER Peak MW
2010	0	
2011	25	4
2012	71	12
2013	118	19
2014	164	26
2015	260	42
2016	374	61
2017	467	75
2018	559	90
2019	652	104
2020	745	119

AEP-East

Ohio Customer Choice		
	GWh	SUMMER Peak MW
2010	0	0
2011	164	32
2012	397	67
2013	572	95
2014	746	124
2015	1,041	176
2016	1,411	232
2017	1,760	291
2018	2,109	347
2019	2,458	405
2020	2,807	460

Appendix I, Renewable Energy Technology Screening

Levelized Cost of Renewables versus Avoided Production Cost

Type	Energy Source	$/MWh
Landfill Gas3.20925Combustion Turbine	Gas	-52.68
Incremental Hydro	Hydro	-37.95
New 24 MW Hydro	Hydro	-10.56
Anaerobic Digester0.173270566491537Int. Comb. Engine	Gas	-4.74
Anaerobic DigesterDairy CowInt. Comb. Engine	Anaerobic Digester	-4.74
100 MW Wind Farm 1 SPP PTC	SPP PTC	44.29
100 MW Wind Farm 2, PJM PTC	PJM PTC	45.93
Geothermal	Geothermal	69.70
100 MW Wind Farm SPP, no PTC	SPP no PTC	71.38
100 MW Wind Farm PJM, no PTC	PJM no PTC	73.13
New 2 MW Hydro	Hydro	102.56
McKinsey 2020 Solar - West (nth of a kind)	Solar	152.51
McKinsey 2020 Solar - East (nth of a kind)	Solar	203.34
Solar Installation 10 MW fixed Tilt thin film a-Si	Solar	226.85
SoCalEd 1 MW rooftop	Solar	233.36
SoCalEd 2 MW rooftop	Solar	317.88

AMERICAN ELECTRIC POWER

Appendix J, Capacity Additions by Company

Period	Summer*	Winter	AEP CC	AEP CT*	AEP D CC2	AEP Solar	AEP Wind**	APCo CC	APCo CT*	APCo D CC2	APCo Solar	APCo Wind**
10-Year IRP Period	2010	2010/11				296	2.01					2.01
	2011	2011/12				150	2.00					
	2012	2012/13				150	2.00					
	2013	2013/14			1	380	6.00			1		
	2014	2014/15				380	8.00					
	2015	2015/16				380	5.00					
	2016	2016/17				380	3.00					
	2017	2017/18		4		380	1.00		4			
	2018	2018/19		4		380	2.00		2			
	2019	2019/20				380	3.00					
	2020	2020/21				450	2.00					
Extended Planning Period	2021	2021/22		4		650	2.00		2			0.67
	2022	2022/23					4.00					
	2023	2023/24	1			660	3.00	1				
	2024	2024/25					3.00					
	2025	2025/26				272	3.00					
	2026	2026/27	1				3.00	1				
	2027	2027/28				363	2.00					
	2028	2028/29										
	2029	2029/30				453						
	2030	2030/31		4					4			

Summer*	Winter	CSP CC	CSP CT*	CSP D CC2	CSP Solar	CSP Wind**	I&M CC	I&M CT*	I&M D CC2	I&M Solar	I&M Wind**
2010	2010/11				119						
2011	2011/12				75	1.00					
2012	2012/13				80	0.50					1.00
2013	2013/14				152	0.50					3.00
2014	2014/15				152	0.80					6.00
2015	2015/16				152	1.67					
2016	2016/17				152	1.00					
2017	2017/18				171						
2018	2018/19				171	1.00					
2019	2019/20				171	1.50					
2020	2020/21				270						1.00
2021	2021/22				163	1.33					
2022	2022/23					2.00					
2023	2023/24				325	1.00					1.00
2024	2024/25					1.00					1.00
2025	2025/26				136	1.00					1.00
2026	2026/27					1.00					
2027	2027/28				181	1.00					
2028	2028/29										
2029	2029/30				227						
2030	2030/31										

Summer*	Winter	KPCo CC	KPCo CT*	KPCo D CC2	KPCo Solar	KPCo Wind**	OPCo CC	OPCo CT*	OPCo D CC2	OPCo Solar	OPCo Wind**
2010	2010/11									178	
2011	2011/12									75	1.00
2012	2012/13									90	0.50
2013	2013/14					2.00				228	0.50
2014	2014/15									228	1.20
2015	2015/16									228	3.33
2016	2016/17									228	2.00
2017	2017/18									209	1.00
2018	2018/19		2							209	1.00
2019	2019/20									209	1.50
2020	2020/21					1.00				180	
2021	2021/22		2							488	
2022	2022/23										2.00
2023	2023/24									325	1.00
2024	2024/25										1.00
2025	2025/26									136	1.00
2026	2026/27					1.00					1.00
2027	2027/28									181	1.00
2028	2028/29										
2029	2029/30									227	
2030	2030/31										

Capacity (MW/Unit)	CC	CT	D CC2	Solar	Wind**
Summer	611	79	540	0.050	50
Winter	660	86	625	0.080	50

* To qualify for Summer availability status a resource must be available by June 1st of that year.

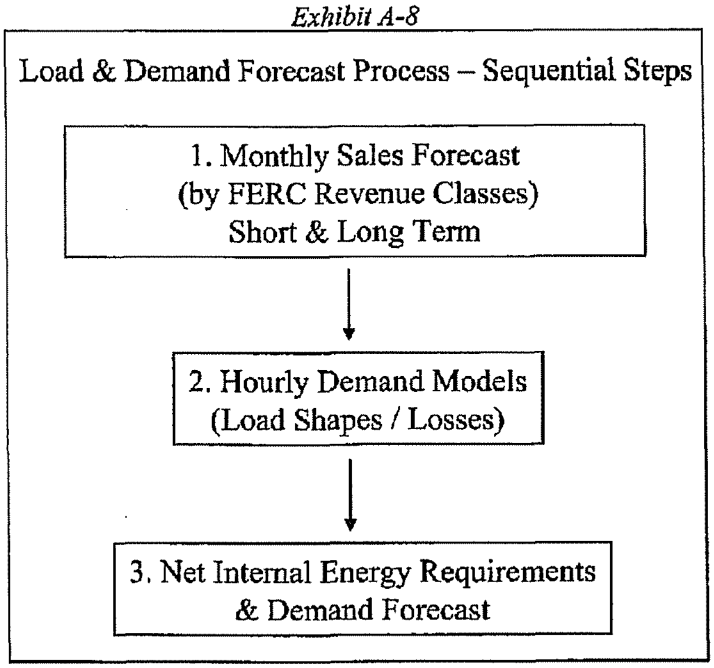
** Wind resources must be completed by December 31st of the previous year to qualify for Summer availability status. A unit marked available for the Summer of 2010 must be completed no later than 12/31/2009

Appendix K, Load Forecast Modeling

Process Summary

AEP utilizes a collaborative process to develop load forecasts. Customer representatives and other operating company personnel routinely provide input on customers (larger customers in particular) and economic conditions. Taking this input into account, the AEP Economic Forecasting group analyzes data, develops and utilizes economic and load forecast data and models, and computes load forecasts. Economic Forecasting and operating company management team members review and discuss the analytical results. The groups work together to obtain the final forecast results. Forecast updates are considered at least two times a year (or more often if deemed necessary).

Exhibit A-8



The electric energy and demand forecast modeling process is the accumulation of three specific forecast model processes as reflected in ***Exhibit A-8.*** The first process models the consumption of electricity at the aggregated customer premise level. These aggregated levels are the FERC revenue classifications of residential, commercial, industrial, other, and municipals and cooperatives. It involves modeling both the short- and long-term sales. The second process contains models that derive hourly load estimates from blended short- and long-term sales, estimates of energy losses for distribution and transmission, and class and end-use load shapes. The aggregate revenue class sales and energy losses is generally called "net internal energy requirements." The third process reconciles historical net internal energy requirements and seasonal peak demands through a load factor analysis which results in the load forecast.

The FERC revenue classes of residential, commercial, industrial, other and municipal and cooperatives are analyzed and forecasted separately. This categorization of customers' premise meter readings allows for customers with like electrical consumption characteristics and behaviors to be modeled together. Similarly, utilizing separate short and long-term sales forecast models capitalizes on the strengths of each methodology.

Energy Sales Modeling

The short-term forecasts are developed utilizing autoregressive integrated moving average (ARIMA) models that incorporate weather and binary variables. Heating and cooling degree-days are the weather variables included in the model development. The short-term forecast period extends for up to 18 months on a monthly basis. These models are utilized to forecast all FERC classes and a number of large individual customers.

The long-term forecasts are developed utilizing a combination of econometric and Statistically Adjusted End-Use (SAE) models. The SAE models were developed by Itron Inc. Energy Forecasting unit. The process starts with an economic forecast provided by Moody's Economy.com for the United States as a whole, each state, and regions within each state. These forecasts include forecasts of employment, population, and other demographic and financial variables. The long-term forecast incorporates the economic forecast and other inputs to produce a forecast of kWh sales. Other inputs include regional and national economic and demographic conditions, energy prices, weather data, and customer-specific information.

AEP uses processes that take advantage of the relative strengths of each method. The regression models with time series error terms use the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. While these models provide advantages in the short run, without specific ties to economic factors, they are limited in capturing the structural trends in the electricity consumption that are important for the longer term planning. The long-term process, with its explicit ties to economic and demographic factors, tends to be structured for longer-term decisions.

Residential Sales

For the residential sector, the number of residential customers and usage per customer are modeled separately, and combined to forecast residential energy sales. Residential customers were modeled as a function of mortgage rates, service area employment, and lagged residential customers. Average residential usage is modeled using the SAE model. SAE models are econometric models with features of end-use models included to specifically account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005. SAE models start with the construction of structured end-use variables that embody end-use trends, including equipment saturation levels and efficiency. Factors are also included to account for changes in energy prices, household size, home size, income, and weather conditions. The statistical part of the SAE model is the regression used to estimate the relationship between observed customer usage and the structured end-use variables. The result is a model that has implicit end-use structure, but is econometric in the estimation. The forecast of residential energy sales is the product of residential customers and residential usage.

Commercial Sales

The commercial energy sales model is also an SAE model. In the commercial class, total energy sales are modeled. The primary economic drivers are service area commercial output (GDP), commercial electricity price, state commercial natural gas price and heating and cooling degree-days.

Industrial Sales

The industrial energy sales are forecast in total for the class. Where applicable, the mine power sectors sales are separated before modeling. For the total or total less mine power, energy sales are a function of selected Federal Reserve Board industrial production indexes, regional employment; and electricity and natural gas prices. Where relevant, the mine power energy sales are modeled as a function of state coal production, regional mining employment and mine power electricity price. Customer-specific information such as expansions, contractions and additions and informed judgment are all utilized in producing the forecasts.

Other Sales

Other ultimate sales are generally comprised of public street and highway lighting, municipal pumping, and other sales to public authorities sectors. The public street and highway lighting energy sales are modeled as a function of service area employment. The other sales to public authorities are related to service area employment and heating and cooling degree-days. The other sales forecast is the sum of these forecasts.

Municipal and Cooperatives

The municipal and cooperatives included in internal load are sales to cooperatives, municipals, private systems and state agencies. These are forecast by individual customer and generally are a function of service area employment and heating and cooling degree days.

Blending Short and Long-Term Sales

Forecast values for 2010 are taken from the short-term process. Forecast values for 2011 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2011 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results.

Energy Losses

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, company loss study results are incorporated to apply losses to each revenue class.

Net Internal Energy Requirements

Net internal energy requirement is the sum of the FERC revenue class sales resulting from the blending process and energy losses.

Demand Forecast Model

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Iron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8760 hourly values. These 8760 hourly values per year are the forecast load of the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-PJM, AEP-SPP or total AEP system. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

Appendix L, Capacity Resource Modeling (Strategist) and Levelized Busbar Costs

The overriding objective of the modeling effort was to recommend an optimum system expansion plan, not only from a least-cost perspective but also from the perspectives of risk profile, achievability, and affordability. The analytical model served as the foundation from which all of the perspectives were examined and recommendations made. The process will be continually refined as experience is gained to take into account emerging issues identified by supporting work groups and management.

The Strategist Model

The *Strategist* resource-planning model, developed by *Ventyx*, allows a user to determine the least-cost resource mix for its system (in this case, AEP's East and West zones) from a user-defined set of resource technologies, under prescribed sets of constraints and assumptions. *Strategist* defines the "least-cost resource mix" as the combination of resource additions that ***produces the lowest overall system pre-tax cost (revenue requirement) inclusive of:***

- New resource capital carrying cost and fixed O&M
- Environmental retrofits
  - New-build capacity
  - Capacity (market) purchase costs
  - Total system-wide fuel costs (new-build <u>and</u> existing capacity)
  - Cost of system-wide (replacement) emission allowances (SO_2, NO_x, CO_2)
  - Net (market) "system transaction" cost or revenue (i.e. third-party energy purchases and/or sales).

Strategist allows all aspects of an integrated resource planning study to be considered with the depth and accuracy required for informed decision-making. Hourly chronological load patterns are recognized, detailed production costing logic is utilized, and the system employs a dynamic programming algorithm to develop the "optimal" and large suites of "sub-optimal" portfolios of capacity addition alternatives over a user-defined study period.

Strategist uses several modules (LFA, GAF, PROVIEW) that work in unison to simulate the operation of the generating system, including new resource additions that may be needed to meet future demand growth. These modules calculate the costs of serving a utility system's capacity and energy needs over the defined study period. The Load Forecast Adjustment module (LFA) is used to represent the utility's hourly demand and energy forecast. The Generation and Fuel module (GAF) works with the LFA to simulate the operation of a utility's generating units and any interaction with external markets. The PROVIEW module pulls information from the LFA and GAF modules as well as other generation alternative data to determine the least-cost resource plan for the utility system under prescribed sets of constraints and assumptions.

Strategist develops an initial "macro" (zone-specific) least-cost resource mix for a system by incorporating a wide variety of expansion planning assumptions including:

- Characteristics (e.g. capital cost, construction period, operating life) of resource addition alternatives that are available to meet future capacity needs

- Operating parameters (e.g. capacity ratings, heat rates, forced outage rates, etc) of existing and new units
- Fuel prices
- Prices of external market energy, capacity, and emission allowances
- Reliability constraints (e.g. minimum reserve margin targets, loss of load hours, unserved energy)
- Emission limits and environmental compliance options

All of these assumptions, and others, are considered in order to develop an integrated plan that best suits the utility system being analyzed.

To reiterate, *Strategist* does <u>not</u> develop a full "cost of service" (COS) profile. It considers only costs that change from plan to plan, not costs that are fixed, such as embedded costs of existing generating capacity or distribution costs. Transmission costs are included only to the extent that they are associated with new generating capacity. Specifically, *Strategist* includes and ultimately recognizes in its "incremental revenue requirement" output profile:

- Fixed costs of capacity additions, i.e. carrying charges on capacity and associated transmission based on a weighted average cost of capital (WACC) and fixed O&M
- Fixed costs of any capacity purchases
- Variable costs of the entire fleet of existing and any added units. This includes fuel, purchased energy, the market replacement cost of emission allowances (SO_2 and NO_X, and CO_2 in appropriate cases), and variable O&M costs. In addition, revenue from external energy transactions (Off-System Sales) is netted against these costs

Due to the netting of Off-System Sales revenues against variable costs, depending on the market spreads for energy, *Strategist* outcomes can represent relative "longer" or "shorter" market energy positions that can have significant bearing on the resulting net system cost and determination of a least-cost plan.

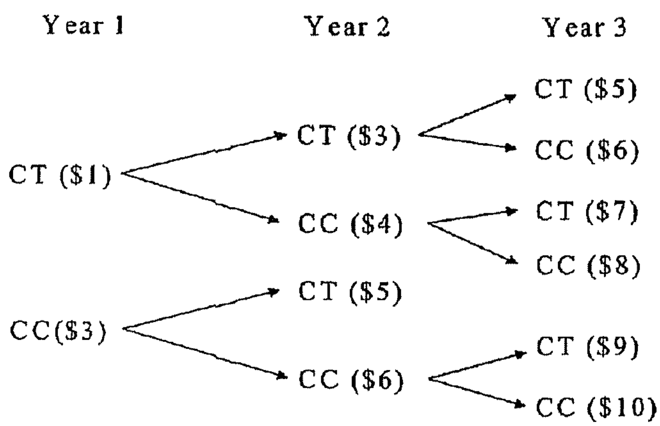
In summary, *Strategist* models the approach AEP uses to determine jurisdictional generation revenue requirements at an integrated, system level. For the purpose of comparing plans, these costs are expressed on a Cumulative Present Worth (CPW) basis for each plan, using standard calculation methods and a 9.0% WACC.

Overview of Need for Modeling Constraints

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from *hundreds of thousands* of possible resource alternative combinations created by the module's chronological "dynamic programming" algorithm. On an annual basis, each capacity resource alternative combination that satisfies its least-cost objective function through user-defined constraints (in this case, a "minimum" on-going capacity reserve margin) is considered to be a feasible state and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations as well as the number of feasible states increases approximately exponentially with the number of resource alternatives being considered.

Exhibit A-9 offers a very simplistic example of this algorithm. The model has the choice of two capacity types (CT and CC) and must achieve its reserve requirement constraint through some economic combination of the capacity types over a three- year period. **Six** unique plans result after the elimination of one of the more expensive paths.

Exhibit A-9 Strategist chronological "dynamic programming" algorithm



* Note: Path "CC (Yr.1)" - CT (Yr.2)" eliminated from further consideration in Yr.3 because its cumulative cost ($5) is greater than a similar path - "CT (Yr. 1) - CC (Yr. 2)" costing $4

As can be seen in this example, the potential for creating hundreds of thousands of alternative combinations and feasible states can become an extremely large computational and data storage problem, if not constrained in some manner. The Strategist model includes a number of input variables specifically designed to allow the user to further limit or constrain the size of the problem the model is attempting to solve. Several of these variables focus on limiting the number of a particular resource alternative that can be considered by the model during the Planning Period. In addition, other variables limit the years that a particular alternative is available for selection by the model.

Appendix M, Utility Risk Simulation Analysis (URSA) Modeling

The risk analysis of the five alternative IRP plans was done with the "Utility Risk Simulation Analysis" model (URSA), which was developed by AEP's Risk Management group. URSA was designed not only to estimate the risk in IRP plans but also to quantify one-year-ahead Earnings at Risk and for a variety of other risk-analytic purposes.

URSA is a Monte Carlo simulation model that represents the daily operation of AEP's assets under a large number of possible alternative futures. As noted above, for the IRP risk analysis, 1,399 alternative futures, each with its own, unique set of daily realizations of risk factors, were treated.

URSA is similar to a physical planning model such as Power Cost Inc.'s Gentrader, but it implements some computational economies to permit consideration of so many alternative futures. Notably, URSA treats only the peak and off peak periods of each day, not each hour. On the other hand, URSA does not reckon with "typical weeks" as many other structural models do, but rather treats explicitly each day of each alternative future. The aim of this approach is to produce a realistic depiction of unit commitment and dispatch.

1. Risk Factor Simulation

The risk analysis begins with a simulation of the daily values of the risk factors for each day of the period 2009-2020, for 1,399 alternative possible futures.

The price and load risk factors vary from day to day within each possible future in accordance with the outcomes of an analysis of the historical variations in these factors, including serial- and cross-correlation, and their relationship to the weather. The raw results obtained from the risk factor model are scaled to ensure that in each simulated year and month, the monthly means of the simulated risk factors agree with the economic forecast of these prices and loads, upon which the IRP is based.

The unit-specific outages also vary from day to day, but independently of the price and load risk factors. Unit outages are determined by a simple, binomial model that depends on the assumed rate of availability for the given unit and an assumed number of days out in case of forced outage. Simulated over many cases, the binomial model produces, for the given unit, an average rate of availability equal to the assumed rate.

2. Utility Operations in View of Given Risk Factors

On each day such day, the risk factors take on given values; AEP and its counterparties then act optimally to exercise any optionality that they may have; physical and financial results of these actions are then calculated and recorded; and the simulation proceeds to the next day.

The optionality in AEP's asset portfolio includes:

- to commit or not to commit any given thermal generating unit to the grid,
- to exercise or not to exercise any power purchase or sale options that it may own,
- how much power to produce from each committed thermal unit,
- how much water to run down, or pump up, at the Smith Mountain Hydro Pumped Storage facility,
- whether and in which direction to transmit power along the AEP West tie.

Under PJM commercial relations, much of this optionality is, in fact, exercised by PJM on AEP's behalf, based on structured commercial bids submitted to PJM by AEP. But it is assumed that the result of the bidding process and PJM's consequent decision-making is the same as if AEP were making these decisions optimally on its own behalf.

3. Representation of the Utility

a. Businesses

The URSA model divides AEP into three businesses:

- retail power supply,
- wholesale power supply and
- fuel supply,

each with its own set of activities and financial results. This division is a schematic one and does not correspond precisely to actual business divisions of AEP. Since, as explained below, fuel and allowance contracts are not treated in the IRP, the fuel supply business's role in the IRP simulations is merely to buy fuel and allowances at market and transfer them to the units. This always results in zero net revenues for the fuel supply business.

The total required revenues of the three businesses are the required revenues of AEP as a whole. Typically the activities of the wholesale business diminish, or make a negative contribution to, required revenue. Those of the retail business, which is responsible of the costs of supplying the native load, typically make a positive contribution to net revenue. The contribution of the fuel supply business is zero, since any fuel or allowances purchased at spot are immediately transferred at the same price.

The model does not treat AEP's transmission or distribution activities, or the corresponding revenues and expenditures. These are assumed to be the same for each IRP case considered.

In any case, the IRP risk analysis, in contrast to some other risk analyses to which this same model is applied, has little to do with these schematic divisions of AEP. Therefore, while the model produces business-specific results, IRP risk results are reported for AEP in total and not by business.

b. Assets

As reckoned with in this study, AEP's East assets consist of:

- thermal (steam and combustion) generating units,
- Smith Mountain pumped storage facility, and
- power purchase and sales contracts.

For analytical convenience, the model treats AEP's hydro generation, other than hydro pumped storage, as a power purchase contract with quantities supplied on a fixed schedule. For the purposes of the study, the returns to AEP's fuel purchase contracts, which typically expire within the next few years, are not treated. Instead, fuel expenditures are reckoned as if all fuel were purchased at spot. Also, returns to AEP's endowment of emissions allowances are not treated; here as with fuel, AEP's expenditures are reckoned at the simulated spot price.

c. Power Supply Obligations

The two power supply businesses are responsible for different sets of power sales contracts. For the East, the sales contracts of the retail power supply business are:

- AEP East load served on a tariff basis
- Buckeye Power
- the 250 MW tie to AEP West, which is modeled as a call option owned by the West

Those of the East wholesale power supply business are:

- certain municipals served on a full requirements basis and connected to the AEP grid,

Total power delivery obligations under all power sales contracts constitute the total load of the utility.

d. Power Supply Resources

To satisfy these obligations, the two power supply businesses jointly operate a given set of power generating units and manage a given set of power purchase contracts. The generating units are:

- the AEP East fleet of steam and combustion generating units and
- the Smith Mountain pumped storage facility.

The power purchase contracts are:

- the AEP East hydro units (which are modeled as a power purchase contract),
- both East, some capacity purchases during early future years,
- a set of power purchase contracts with OVEC, and
- some small sources of supply such as Summersville.

The capacity purchases contribute to the satisfaction of the operating reserve requirement for AEP East in total. But any energy that would flow from these suppliers is treated as a spot power purchase, not a contractual one.

The retail power supply business, as modeled, has the first call on all power supply resources, and takes the most economical opportunities. In each period, it specifies the energy that it takes from each generating unit and power purchase contract so as to satisfy exactly its total obligations under its power sales contracts while minimizing the cost of doing so. The retail business does not normally engage in spot power sales, but it will purchase spot power whenever doing so would reduce cost.

The wholesale power supply business, as modeled, has the second call on all power supply resources, taking energy from generating units and from power supply contracts only to the extent that anything is left by the retail business. It does this so as to maximize total net revenues from sales (which effectively minimizes AEP's required revenue). It engages freely in spot power sales.

e. Spot Power Supply

The difference between the total power generated or taken under purchase contracts on the one hand, and the total deliveries required under power sales contracts on the other, defines the utility's net spot market sales. URSA does not treat explicitly any short-term power deals not resulting in physical delivery. Effectively, trading activities apart from purchases or sales of physical power at spot are assumed to yield a zero net return.

Because the wholesale power supply business has the second and last call on the resources able to deliver power, it determines the total power produced. By this means it effectively also determines net spot power sales of the total utility. For example, if the retail business decides upon a net spot **purchase** of 100 MWh, and the final dispatch implies a net spot **sale** of 200 MWh, then the wholesale business sells 300 MWh at spot: the 100 MWh purchased by the retail business plus an additional 200 MWh to other purchasers.

4. Reckoning of Costs

a. Transfer Pricing

URSA's design lays some emphasis upon the appropriate prices for valuing transfers between different business units. This permits economically correct estimation of the revenue requirement contributed by each asset, and of the associated risk. But since any scheme of transfer prices nets out in total, the particular scheme employed has no effect on the estimation of costs for AEP East.

The value at which power is transferred from a generating unit to a power supply business employing it is correctly reckoned at the spot price. The gain or loss that may arise if this same power is sold at a contracted price does not belong to the generating unit, but to the given power supply contract, here viewed as an asset of the given power supply business. This applies even if the "contract" in question is the obligation to serve the retail load. This implies that any generating unit considered separately, which typically does not run unless it is in the money, makes a negative contribution toward (diminishes) required revenue. On the other hand, the power sales "deal" that represents the obligation to serve makes a substantial positive contribution to required revenue.

Based on these and analogous considerations, the following transfer prices apply:

- thermal generating units
  - buy fuel at the spot price,
  - buy emissions allowances at the spot price, and
  - sell power at the spot price;
- Smith Mountain
  - buys power at the spot price and
  - sells power at the spot price;
- power purchase contracts
  - buy power at the contract price and
  - sell power at the spot price;
- power sales contracts
  - buy power at the spot price and
  - sell power at the contract price

A consequence of these conventions is that all required revenue is due to assets, and in particular, the gains from spot power sales are due to the sources of the power sold, which are the generating units and power purchase contracts employed to produce the sold power.

It is worth repeating that for the utility in total, these transfer pricing considerations wash away.

b. Operating Companies

Because the AEP East system is fully integrated, and because the interest of the risk analysis is with total East required revenue, the analysis pays no attention to operating companies, but only simulates power supply activities and financial returns for AEP East in total.

c. Calculation of Required Revenue

Required revenue is the sum of all costs minus all revenues. Revenues from serving native load are assumed to be zero; that from transmitting on the AEP West tie is assume to be the difference in East-West power prices times the quantity transmitted; and those from supplying other power sales deals are assumed to be exactly the same as the cost of the power supplied. Since no fuel or allowance deals are reckoned with, there is no revenue from these sources. If a megawatt-hour is produced at some unit and supplied to the native load, the unit is credited with the market value of the power, but the load is correspondingly debited, and what is left in total is only the cost of producing the power. If the power is supplied to some other power sales deal then the profit, since the contract revenue is assumed to equal the cost of the power delivered, is the difference between the spot power price and the cost of producing the power supplied. The gain is the same if the power is supplied directly to the spot market. Hence, in aggregate, required revenue is the cost of satisfying the obligation to serve (including the West tie), minus the profits of selling, at spot, all other power produced.

d. Treatment of Contract Revenue -- Differences from Strategist Model

It was just said that URSA assumes that the fees obtained from the customer for external transactions are always precisely the same as the cost of providing the power. The reason is to wash these sales of possible gain or loss, and thus to purge from the risk analysis any risk due to external transactions. The risk analysis thus considers only risk arising from the obligation to serve the native load.

This assumption with regard to contract revenues differs from assumptions used in the *Strategist* analysis, which is used to develop the IRP plans. There, particular contractual prices are assumed for the various deals and are used to determine total contract revenues. The assumptions used in the risk analysis result in greater contract revenues on power sales, with the result that in total, URSA analysis calculates a smaller net present value required revenue for the period 2006-2030 than *Strategist* does. This is merely for purposes of the risk analysis and is not intended to supercede the *Strategist* estimate.

On the contrary, the *Strategist* assumption with regard to contract revenues is better for estimating total, net present value required revenue; while the URSA assumption is better for analyzing risks that arise particularly from the obligation to serve the native load.

5. Technical Comparison of URSA with Strategist

In late 2005 and early 2006, AEP's Risk Management and Corporate Planning groups collaborated in a technical comparison of detailed results from URSA and from *Strategist* under equivalent input assumptions. The inquiry particularly focused on costs and rates of operation (capacity factors) at AEP East and West generating units; and on total system power exports and imports, and associated revenues.

The conclusion was that for the same inputs, the two models substantially agreed in the rates of operation of AEP's various units, and in the associated costs. The main difference was that marginal, mid-stack units tend to be operated somewhat less by URSA than by *Strategist*. The reason for this is that URSA, with its daily unit commitment paradigm, cherry-picks short sequences *of favorable days when these units will be committed. This optionality is not available within* Strategist's "typical week" framework, and *Strategist* therefore tends to commit such units during the entire week, and to keep them running at minimum during unfavorable periods. This difference does not, however, impede the use of URSA to analyze the risk around cases developed using *Strategist*. In any case, since there is very little mid-stack capacity in AEP's East fleet, this difference is material mainly to the analysis of the West fleet.

URSA and *Strategist* produced very similar estimates of power imports and exports for AEP East; for AEP West, URSA produced marginally smaller estimates of exports and larger estimates of imports, due to the marginally lower rate at which it operated the West's relatively substantial holding of mid-stack units.

SUPPLEMENTAL Appendix 3

4901:5-5-06 Resource Plans Requirements	IRP Section Reference
(B) In the long-term forecast report filed pursuant to rule 4901:5-3-01 of the Administrative Code, the following must be filed in the forecast year prior to any filing for an allowance under sections 4928.143(B)(2)(b) and (c) of the Revised Code:	
(1) Existing generating system description. (a) The reporting person shall provide a brief summary narrative of the existing electric generating system. If a hearing is to be held on the forecast in the current year, the reporting person shall submit to the commission with its long-term forecast report, the anticipated operating, maintenance, and fuel expense of each unit for each year of the forecast period. The commission may make exceptions to this paragraph for good cause.	Section 1.2, Section 3, Appendix A
(b) A summary of the pooling, mutual assistance, and all agreements for purchasing from and selling power and energy to other utilities or nonutility generators, including costs and amounts, shall be provided.	Section 1.2.2, Appendix D
(2) Need for additional electricity resource options. The reporting person shall describe the procedure followed in determining the need for additional electricity resource options. All major factors shall be discussed, including but not limited to:	Section 1, Section 5
(a) System load profile.	Section 4, Appendix F
(b) Maintenance requirements of existing and planned units.	Section 3
(c) Number of units, unit size, and availability of existing and planned units.	Section 9
(d) Forecast uncertainty.	Section 8.3
(e) Electricity resource option uncertainty with respect to cost, availability, commercial in-service dates, and performance.	Section 10, Appendix M
(f) Lead times for construction or implementation of planned electricity resource options.	Section 12.3
(g) Power interchange with other electric systems, including consideration of the ability to buy and sell power.	Sections 5.1 & 5.2
(h) Price-responsive demand and price elasticity due to the implementation of time-differentiated pricing options and assessments of the value of lost load.	Section 6.4.2, Section 7.6
(i) Regulatory climate.	Section 2
(j) Reliability criteria, including a discussion and analysis of the reporting person's reliability criteria and factors influencing their selection, including, but not limited to: (i) Reliability measures used and factors including the selection. (ii) Engineering analysis performed. (iii) Economic analysis performed. (iv) Any judgments applied.	Section 5
(3) Resource plan.	
(a) This paragraph shall include the electric utility's projected mix of resource options to meet the base case projection of peak demand and total energy requirements.	Section 11
(b) A discussion of the electric utility's projected system reliability shall be presented. It shall include:	
(i) A discussion of the future adequacy of the electric utility's projected system in both the short- and long-term.	Section 12
(ii) A discussion of the future adequacy of fuel supplies in both the short- and long-term. Additionally, the reporting person shall provide, for the forecast period, a description of its overall fuel procurement policies and procedures. A description of the system's fuel requirements, the system's geographic source of fuel supply, and the percentage of fuel supply under contract shall be included.	Supplemental Appendix 5

SUPPLEMENTAL Appendix 3

4901:5-5-06 Resource Plans Requirements	IRP Section Reference
(c) The electric utility shall demonstrate the cost-effectiveness of the plan through a comparison over the ten-year forecast horizon of the revenue requirement and rate impacts of the selected plan and alternative plans evaluated. The selection of the plan shall demonstrate adequate consideration of the risks, reliability, and uncertainties associated with the person's selected plan and alternative plans, and of other factors the electric utility deems appropriate.	Sections 9 & 10
(d) The methodology for arriving at the plan must be fully explained and described. The description must be sufficiently explicit, detailed and complete to allow the commission and other knowledgeable parties to understand how the assessment was conducted. This description shall also include: (i) A general discussion of the decision-making process, criteria, and standards employed by the electric utility as it relates to the development of the resource plan. (ii) A discussion of how the plan is consistent with the overall planning objectives of paragraph (A) of rule 4901:5-5-03 of the Administrative Code. (iii) A discussion of key assumptions and judgments used in development of the resource plan.	Sections 1, 2, & 11; Apendices K, L, & M
(e) The reporting person shall provide information sufficient for the commission to determine the reasonableness of the resource plan, including:	
(i) The adequacy, reliability, and cost-effectiveness of the plan.	Section 9
(ii) Whether the methodology used to develop the plan evaluates demand-side management programs and nonelectric utility generation on both sides of the meter in a manner consistent with electric utility's generation and other electricity resource options. At a minimum, the total resource cost test as defined in rule 4901:1-39-01 of the Administrative Code, should be used to determine the cost-effectiveness of demand-side management programs.	Section 7
(iii) Whether the plan gives adequate consideration to the following factors: (a) Potential rate and customer bill impacts of the plan. (b) Environmental impacts of the plan and their associated costs. (c) Other significant economic impacts and their associated costs. (d) Impacts of the plan on the financial status of the company. (e) Other strategic considerations including flexibility, diversity, the size and lead time of commitments, and lost opportunities for investment. (f) Equity among customer classes. (g) The impacts of the plan over time. (h) Such other matters the commission considers appropriate.	Section 12

SUPPLEMENTAL Appendix 4

Forecasted (Summer) PEAK DEMAND Comparison by Recent "Forecast Vintage"

Columbus Southern Power Company

	Summer Peak (MW)				Summer PEAK Variances		
		Comparable Forecast Vintages					
	Sep-09	Sep-09 (Rev)*	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D3)*	*2010 IRP*	*Latest Forecast*			
2010	4,308	4,308	4,266	4,474	-1.0%	3.9%	4.9%
2011	4,382	4,382	4,264	4,290	-2.7%	-2.1%	0.6%
2012	4,442	4,407	4,278	4,260	-2.9%	-3.3%	-0.4%
2013	4,507	4,431	4,314	4,289	-2.6%	-3.2%	-0.6%
2014	4,560	4,440	4,313	4,294	-2.9%	-3.3%	-0.4%
2015	4,611	4,446	4,301	4,284	-3.3%	-3.6%	-0.4%
2016	4,654	4,442	4,278	4,262	-3.7%	-4.0%	-0.4%
2017	4,717	4,458	4,279	4,268	-4.0%	-4.3%	-0.3%
2018	4,761	4,456	4,279	4,274	-4.0%	-4.1%	-0.1%
2019	4,800	4,399	4,267	4,270	-3.0%	-2.9%	0.1%
2020	4,829	4,332	4,229	4,241	-2.4%	-2.1%	0.3%

Ohio Power Company

	Summer Peak (MW)				Summer PEAK Variances		
		Comparable Forecast Vintages					
	Sep-09	Sep-09 (Rev)*	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D3)*	*2010 IRP*	*Latest Forecast*			
2010	5,324	5,324	5,116	5,167	-3.9%	-3.0%	1.0%
2011	5,370	5,370	5,131	5,236	-4.5%	-2.5%	2.1%
2012	5,044	5,005	4,784	4,877	-4.4%	-2.5%	2.0%
2013	5,099	5,016	4,811	4,895	-4.1%	-2.4%	1.7%
2014	5,134	5,002	4,808	4,894	-3.9%	-2.1%	1.8%
2015	5,165	4,985	4,802	4,891	-3.7%	-1.9%	1.8%
2016	5,186	4,956	4,786	4,879	-3.4%	-1.6%	1.9%
2017	5,222	4,942	4,790	4,886	-3.1%	-1.1%	2.0%
2018	5,247	4,917	4,790	4,888	-2.6%	-0.6%	2.0%
2019	5,270	4,838	4,777	4,878	-1.2%	0.8%	2.1%
2020	5,279	4,745	4,731	4,834	-0.3%	1.9%	2.2%

AEP East

	Summer Peak (MW)				Summer PEAK Variances		
		Comparable Forecast Vintages					
	Sep-09	Sep-09 (Rev)*	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	*2010 LTFR*	*2010 LTFR (REV Form FE-D3)*	*2010 IRP*	*Latest Forecast*			
2010	21,453	21,453	20,805	21,144	-3.0%	-1.4%	1.6%
2011	21,813	21,813	20,825	21,200	-4.5%	-2.8%	1.8%
2012	22,041	21,967	20,992	21,322	-4.4%	-2.9%	1.6%
2013	22,321	22,162	21,193	21,500	-4.4%	-3.0%	1.4%
2014	22,524	22,272	21,230	21,547	-4.7%	-3.3%	1.5%
2015	22,721	22,376	21,247	21,571	-5.0%	-3.6%	1.5%
2016	22,869	22,427	21,214	21,542	-5.4%	-3.9%	1.5%
2017	23,096	22,557	21,272	21,615	-5.7%	-4.2%	1.6%
2018	23,273	22,638	21,334	21,685	-5.8%	-4.2%	1.6%
2019	23,444	22,611	21,389	21,752	-5.4%	-3.8%	1.7%
2020	23,561	22,530	21,369	21,736	-5.2%	-3.5%	1.7%

* In a 6/1/10 Company response to a Staff inquiry (e-mail from Steve Nourse to Dan Johnson, et al) in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR, the CSP and OPCo 2010 LTFR Form 'FE-D3' was revised to reflect an "expanded" view of DSM activity *beyond* the initial (3-year) program period (2009-2011) originally projected --and filed-- in order to capture the impacts of long-term DSM benchmark requirements under S.B. 221. Such (expanded) DSM basis was subsequently reflected in the 'Apr-10' and 'Oct-10' peak demand forecasts shown above.

Other Notes:

- o For comparative purposes, forecasted Peak Demand profiles are reflective of DSM initiatives, but are not reflective of Ohio Customer Choice projections
- o For current planning purposes only, Ohio Power Company Sales for Resale customer Wheeling Power Company is assumed to merge with affiliate Appalachian Power Company (i.e. no impact on 'AEP East' results) effective 1-1-2012

SUPPLEMENTAL Appendix 4

Forecasted ENERGY REQUIREMENT Comparison by Recent "Forecast Vintage"

Columbus Southern Power Company

	Energy Requirement (GWh)	Comparable Forecast Vintages			ENERGY Variances		
	Sep-09	Sep-09 (Rev) *	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	2010 LTFR	2010 LTFR (REV Form FE-D1)	2010 IRP	Latest Forecast			
2010	22,272	22,272	22,094	22,910	-0.8%	2.9%	3.7%
2011	22,738	22,738	22,002	22,506	-3.2%	-1.0%	2.3%
2012	23,034	22,870	22,154	22,650	-3.1%	-1.0%	2.2%
2013	23,283	22,933	22,274	22,769	-2.9%	-0.7%	2.2%
2014	23,519	22,961	22,233	22,728	-3.2%	-1.0%	2.2%
2015	23,760	22,994	22,120	22,617	-3.8%	-1.6%	2.2%
2016	24,006	23,029	22,033	22,531	-4.3%	-2.2%	2.3%
2017	24,210	23,022	21,981	22,482	-4.5%	-2.3%	2.3%
2018	24,399	22,999	21,948	22,451	-4.6%	-2.4%	2.3%
2019	24,571	22,745	21,853	22,358	-3.9%	-1.7%	2.3%
2020	24,744	22,493	21,681	22,187	-3.6%	-1.4%	2.3%

Ohio Power Company

	Energy Requirement (GWh)	Comparable Forecast Vintages			ENERGY Variances		
	Sep-09	Sep-09 (Rev) *	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	2010 LTFR	2010 LTFR (REV Form FE-D1)	2010 IRP	Latest Forecast			
2010	30,809	30,809	30,462	30,754	-1.1%	-0.2%	1.0%
2011	31,245	31,245	30,603	31,331	-2.1%	0.3%	2.4%
2012	29,336	29,127	28,388	29,068	-2.5%	-0.2%	2.4%
2013	29,547	29,103	28,494	29,163	-2.1%	0.2%	2.3%
2014	29,697	28,992	28,489	29,159	-1.7%	0.6%	2.4%
2015	29,834	28,868	28,448	29,122	-1.5%	0.9%	2.4%
2016	29,979	28,751	28,412	29,090	-1.2%	1.2%	2.4%
2017	30,088	28,599	28,369	29,051	-0.8%	1.6%	2.4%
2018	30,182	28,431	28,354	29,039	-0.3%	2.1%	2.4%
2019	30,258	27,966	28,257	28,945	1.0%	3.5%	2.4%
2020	30,335	27,543	28,053	28,744	1.9%	4.4%	2.5%

AEP East

	Energy Requirement (GWh)	Comparable Forecast Vintages			ENERGY Variances		
	Sep-09	Sep-09 (Rev) *	Apr-10	Oct-10	Apr-10 v. Sep-09(Rev)	Oct-10 v. Sep-09(Rev)	Oct-10 v. Apr-10
BASED ON =>	2010 LTFR	2010 LTFR (REV Form FE-D1)	2010 IRP	Latest Forecast			
2010	124,680	124,680	121,863	123,523	-2.3%	-0.9%	1.4%
2011	127,247	127,247	121,716	124,572	-4.3%	-2.1%	2.3%
2012	128,748	128,374	123,044	125,877	-4.2%	-1.9%	2.3%
2013	129,874	129,080	123,868	126,690	-4.0%	-1.9%	2.3%
2014	130,808	129,545	124,012	126,836	-4.3%	-2.1%	2.3%
2015	131,758	130,026	123,885	126,713	-4.7%	-2.5%	2.3%
2016	132,766	130,561	123,941	126,775	-5.1%	-2.9%	2.3%
2017	133,638	130,961	124,111	126,951	-5.2%	-3.1%	2.3%
2018	134,467	131,316	124,400	127,245	-5.3%	-3.1%	2.3%
2019	135,257	131,140	124,641	127,490	-5.0%	-2.8%	2.3%
2020	136,062	131,019	124,764	127,618	-4.8%	-2.6%	2.3%

* In a 6/1/10 Company response to a Staff Inquiry (e-mail from Steve Nourse to Dan Johnson, et al) in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR, the CSP and OPCo 2010 LTFR Form 'FE-D1' was revised to reflect an "expanded" view of DSM activity *beyond* the initial (3-year) program period (2009-2011) originally projected --and filed-- in order to capture the impacts of long-term benchmark DSM requirements under S.B. 221. Such (expanded) DSM basis was subsequently reflected in the 'Apr-10' and 'Oct-10' energy requirement forecasts shown above.

Other Notes:

- For comparative purposes, forecasted Energy profiles are reflective of DSM initiatives, but are not reflective of Ohio Customer Choice projections
- For current planning purposes only, Ohio Power Company Sales for Resale customer Wheeling Power Company is assumed to merge with affiliate Appalachian Power Company (i.e. no impact on 'AEP East' results) effective 1-1-2012

SUPPLEMENTAL Appendix 5
Fuel Adequacy and Fuel Procurement Policy

The generating units of Ohio Power and Columbus Southern Power, known collectively as AEP Ohio, and the other AEP System-East Zone operating companies, which are predominantly coal-fired, are expected to have adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. AEPSC, acting as agent for AEP Ohio, is responsible for the procurement and delivery of fuel to AEP Ohio's generating stations, as well as setting coal inventory target level ranges and monitoring those levels. AEPSC's primary objective is to assure secure, flexible and competitively priced fuel supplies and transportation to meet generation requirements, recognizing the dynamic nature of fuel markets, environmental standards and regulatory requirements. Deliveries are arranged so that sufficient fuel is available at all times.

AEP-East obtains much of its total coal requirements under long-term arrangements, thus assuring the plants of a relatively stable and consistent supply of coal. The table below outlines the percentage of coal supply under contract for AEP Ohio for the years 2011 through 2020.

2011	81.72%
2012	53.70%
2013	46.51%
2014	43.25%
2015	42.50%
2016	44.40%
2017	44.45%
2018	18.97%
2019	7.52%
2020	0.00%

The remaining coal requirements are normally satisfied by making short-term purchases. Occasionally, purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

AEP-East's fuel requirements vary from plant to plant, depending upon such factors as environmental restrictions and boiler design, as well as the demand for electricity. In 2009, coal consumption at AEP-East operated plants aggregated to more than 48 million tons. Of this amount, AEP Ohio plants accounted for nearly 25 million tons. Historically, the coal supplies for the Ohio plants have primarily been provided by operations in Ohio, West Virginia, Kentucky, and Wyoming.

AEPSC, acting as agent for AEP Ohio, is also responsible for the procurement and delivery of gas to two AEP Ohio gas plants. These generating units do not have long term supply contracts as they provide peaking and intermediate load services. The two plants have had significantly low capacity factors with total consumption in 2009 of approximately 4.75 billion cubic feet. In addition, there are adequate fuel supplies available in the market, mitigating the need for long term supply contracts. The plants are served by various pipelines, including Texas Eastern, Columbia Gas and Dominion.

EXHIBIT ____

Kentucky Power Company

REQUEST

Refer to the Wohnhas Testimony at page 15, lines 1-5. One of the reasons given for depreciating the FGD at Big Sandy Unit 2 over 15 years is to reduce the risk of stranded investment in the future.

a. What is Kentucky Power's assessment of the risk of the FGD becoming a stranded investment?

b. Explain why exisitng customers should pay for this future risk.

RESPONSE

a With the increasingly stringent and ever changing position of the EPA and its rule making, the Company believes that it is a medium risk that future EPA rules would result in stranded investment in the DFGD in the absence of a 15-year depreciation period.

b. The investment is being made for the benefit of current customers. Most of the Company's current customers will also be customers in 15 and 25 years from now. The Company is trying to match as best it can the cost to the cost causer in the event the risk is realized.

WITNESS: Ranie K Wohnhas

SC EXHIBIT 3

EXHIBIT ____

Kentucky Power Company

REQUEST

Refer to pages 14-15 of the Wohnhas Testimony.

a. Under Option #1, what is the expected remaining useful life of the existing equipment?

b. Under Option #1, if the expected remaining life of the existing equipment is longer than 15 years, explain why it would not be appropriate to match the depreciation lives of the new environmental control equipment with the expected remaining lives of the existing equipment.

c. Provide the rationale for thinking that the Commission would not allow the continued recovery of all authorized expenses.

d. For Options #1 through #4, explain whether the depreciation lives of the equipment in the various options were the same. If not, why.

RESPONSE

a. Please see response to Commission Staff's First Set of Data Requests, Item No. 12.

b. It is an appropriate option and has been used by AEP as shown on page 2 of the response to Staff 1-90. However, all of those showed an estimated plant life of 60 years. Even though the Company has stated that the service life for Big Sandy Unit 2 could approach 70 years, it is not a guarantee and thus 15 years (service life of 60 years) is more appropriate.

c. The Company is not stating that the Commission would not allow recovery of all authorized expenses.

d. Option #1 was the only option with a 15 year depreciation life. Options #2 and #3 used the remaining life of the equipment because they would be gas units which will not have EPA regulations to hinder their operations. Option #4 is a market option and thus depreciation does not apply.

WITNESS: Ranie K Wohnhas

SC EXHIBIT 4

EXHIBIT ____

SUMMARY

Kentucky Power Co.

Big Sandy Generating Unit Disposition Analysis

Life-Cycle (30-Year, 2011-2040) Economics

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS> .... vs. Option #1-'*BASE*')

	UNIT DISPOSITION ALTERNATIVES				
KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	Retrofit (2015) [(A)] (D-FGD/CCR)	Retrofit (2015) (D-FGD/CCR)	Retire (2015) Repl w/Mkt to 2020, then CC	Retire (2015) Replace w/ ~800-MW CC	Retire (2015) Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	Retrofit (2015) (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario			Option #1	Option #2	Option #3	Option #4	Option #5
$Millions							
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")			69	81	9
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)			(115)	30	(269)
BASE (ORIG)		Path "A"		195	(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")			(346)	(172)	(442)
LOW-Side Sensitivity		Path "A" ("Lower Band")			(498)	(369)	(617)
% (2016-2040)							
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")			1.3%	1.5%	0.2%
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)			-1.7%	0.4%	-3.9%
BASE (ORIG)		Path "A"		3.1%	-1.5%	0.4%	-2.2%
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")			-5.5%	-2.7%	-7.0%
LOW-Side Sensitivity		Path "A" ("Lower Band")			-8.0%	-5.9%	-9.9%
(Levelized) $/MWh (2016-2040)							
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")			1.4	1.7	0.2
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)			(2.4)	0.6	(5.5)
BASE (ORIG)		Path "A"		0.40	(2.0)	0.5	(2.8)
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")			(7.1)	(3.5)	(9.1)
LOW-Side Sensitivity		Path "A" ("Lower Band")			(10.2)	(7.6)	(12.6)

[(A)] For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to 10 Years; recovery period for CC options remain at 30 Years
[(B)] (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast
[(C)] *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

Add'l Notes
o "Retirement" options exclude costs associated w/ socio-economic impacts to the region
o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

SC EXHIBIT 5

SUMMARY

Kentucky Power Co.

Big Sandy Generating Unit Disposition Analysis

Life-Cycle (30-Year, 2011-2040) Economics

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS> .... vs. Option #1-'*BASE*')

	UNIT DISPOSITION ALTERNATIVES				
KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	**Retrofit (2015)** [A] (D-FGD/CCR)	**Retrofit (2015)** (D-FGD/CCR)	**Retire (2015)** Repl w/Mkt to 2020, then CC	**Retire (2015)** Replace w/ ~800-MW CC	**Retire (2015)** Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	**Retrofit (2015)** (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario			Option #1	Option #2	Option #3	Option #4	Option #5
			$Millions				
CO2 Sensitivity	*Jan '11 Forecast* [B]	Path "A" ("No CO2 Policy")			69	81	9
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)			(115)	30	(269)
BASE (ORIG)		Path "A"		195	(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [C]	Path "A" ("Fleet Transition")			(346)	(172)	(442)
LOW-Side Sensitivity		Path "A" ("Lower Band")			(498)	(369)	(617)
SENSITIVITY... Impact of a 5-Year Delay in CO2 Tax							
BASE (ORIG)	*Jan '11 Forecast* [B]	Path "A"				46	(83)
BASE (REV)	*Mar '11 Forecast* [C]	Path "A" ("Fleet Transition")				(152)	(390)

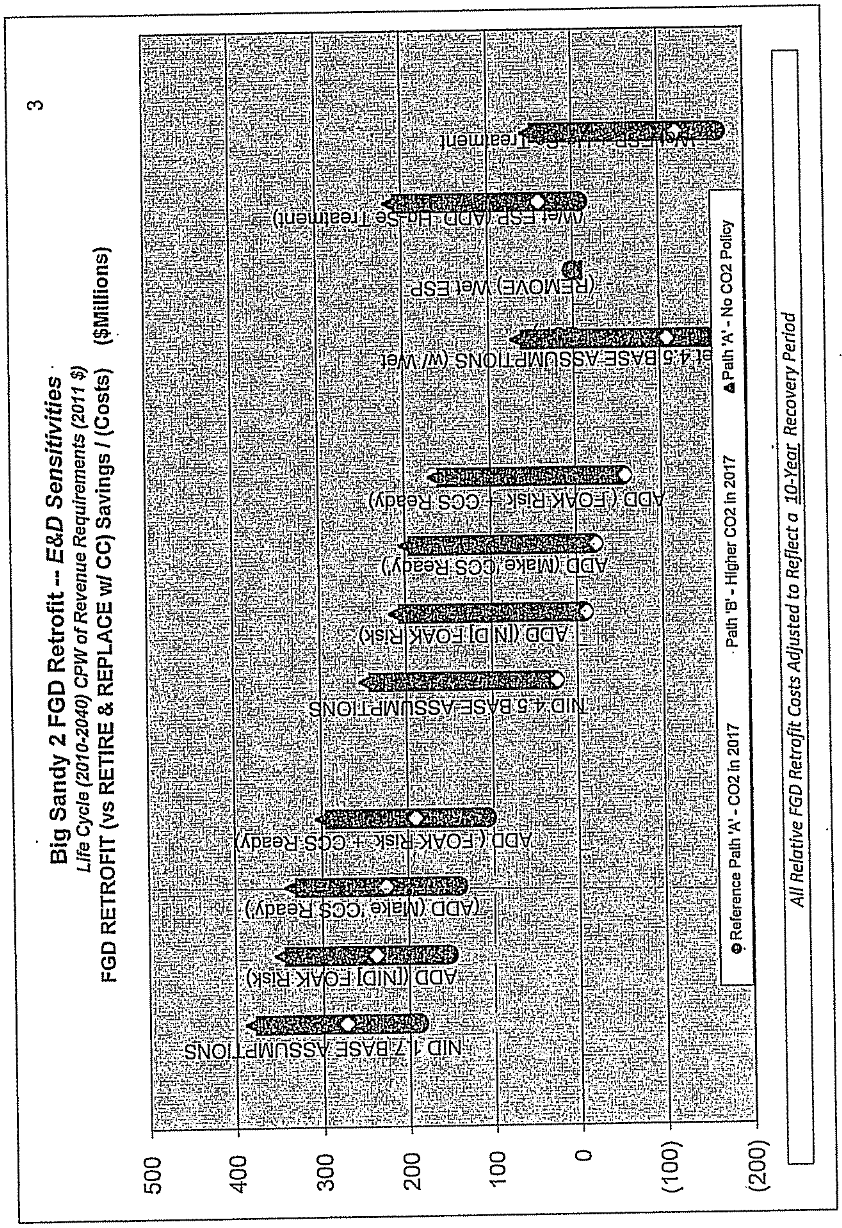
[A] For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to <u>10 Years</u>; recovery period for CC options remain at 30 Years

[B] (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast

[C] *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

Add'l Notes

- o "Retirement" options exclude costs associated w/ socio-economic impacts to the region
- o "Retirement" options established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
- o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of: 1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)


3
Big Sandy 2 FGD Retrofit -- E&D Sensitivities
Life Cycle (2010-2040) CPW of Revenue Requirements (2011 $)
FGD RETROFIT (vs RETIRE & REPLACE w/ CC) Savings / (Costs) ($Millions)
500
400
300
200
100
0
(100)
(200)
NID 1.7 BASE ASSUMPTIONS
ADD (NID) FOAK Risk
ADD (Make 'CCS Ready')
ADD (FOAK Risk + CCS Ready)
NID 4.5 BASE ASSUMPTIONS
ADD (NID) FOAK Risk
ADD (Make 'CCS Ready')
ADD (FOAK Risk + CCS Ready)
REMOVE Wet ESP
Wet ESP ADD Hg-Se Treatment
Reference Path 'A' - CO2 in 2017
Path 'B' - Higher CO2 in 2017
Path 'A' - No CO2 Policy
All Relative FGD Retrofit Costs Adjusted to Reflect a 10-Year Recovery Period

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, pages 14 and 15.

a. Please identify the generally accepted accounting principles that apply to the determination of the time period over which the Company depreciates major capital investments, such as the capital cost of a FGD.

b. Please identify the time period over which the Company would propose to depreciate the cost of the FGD unit according to those generally accepted accounting principles and in the absence of any material risk of future environmental regulations.

c. Please identify cases in which the Public Service Commission of Kentucky has approved a 15 year time period for depreciation of a FGD.

d. Please identify cases in which the Public Service Commission of Kentucky has approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

e. Please identify cases in which the regulatory commissions in other states in which American Electric Power operates have approved a 15 year time period for depreciation of a FGD.

f. Please identify cases in which the which the regulatory commissions in other states in which AEP operates have approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

g. Please list the "increased EPA standards" that could cause operation of this unit not to be economically feasible in the future.

h. Please describe how the Company analyzed the risk associated with those "increased EPA standards" in its economic evaluation of resource alternatives.

i. Please explain how the Company would bear a portion of the risk of stranded investment if the Commission approves recovery through the environmental cost recovery surcharge, and describe the percent of the risk the Company would bear.

j. Please explain, with supporting illustrative calculations, how a 15 year depreciation period would reduce the risk of stranded investment that ratepayers will bear if the Commission approves recovery through the environmental cost recovery surcharge.

RESPONSE

a. The Generally Accepted Accounting Principle (GAAP) that applies to the determination of the time period over which the Company depreciates its investment is the matching principle. The matching principle requires that the asset's cost be allocated to depreciation expense over the life of the asset.

FASB 71 states that if a regulator prescribes a period of time to depreciate an asset that is shorter than the useful life of the asset then using the shorter life is consistent with GAAP.

b. The Company is not proposing a period other than the 15 years since is does not believe it is appropriate to assume an absence of any material risk of future environmental regulations. As stated in response to Staff 1-12, the expected life could reach 70 years and thus the depreciation life would be 25 years.

c. The Company is not aware of any cases in which the KPSC approved a 15 year time period for depreciation of a FGD.

d. The Company is not aware of any cases in which the KPSC approved a shorter time period to recover depreciation in order to reduce the risk of stranded investment.

e. The Company is not aware of any other regulatory commission in other states in which American Electric Power operates has approved a 15 year time period for depreciation of a FGD.

f. In Indiana & Michigan's CPCN filing for a scrubber on one of its Rockport Units in Cause No. 43636, they are asking for a 15 year depreciation period. Please see Attachment 1 to this response as the statutory authority to ask for this time frame..

g. The Company does not know what those future increased EPA standards will be at this time.

h. The Company did not attempt to analyze the risk associated with future unknown increased EPA standards.

i. The Company proposes to make the investment to provide service to its customers at the lowest cost and in accordance with federal law. Under these circumstances the Company should not bear any risk of stranded investment.

j. Attachment 2 to this response is an illustrative calculation comparing the depreciation of an asset over 15 years versus 25 years. You will notice that at the end of 15 years the asset being depreciated over 25 years still has $370M of undepreciated plant (net plant). If the Company were to retire that asset in year 15 (before the end of the 25 year depreciation period), the $370M of net plant is stranded investment. If the asset were to be retired prior to 15 years, both scenarios would have stranded investment, but the asset being depreciated over 15 years would have less stranded investment versus the asset being depreciated over 25 years. Thus, the amount at risk subject to stranded investment is much less.

WITNESS: Ranie K Wohnhas

LexisNexis®

BURNS INDIANA STATUTES ANNOTATED

Statutes current through Act PL 231 of the 2011 First Regular Session
Annotations current through June 28, 2011 for Indiana Supreme Court cases, through June 22, 2011 for Indiana Appellate Court cases, through May 27, 2011 for Indiana Tax Court cases, and through July 8, 2011 for Federal Court cases.

Title 8 Utilities and Transportation
Article 1 Public Utilities
Chapter 2 Indiana Utility Regulatory Commission
[Valuation and Accounting]

Go to the Indiana Code Archive Directory

Burns Ind. Code Ann. § 8-1-2-6.7 (2011)

8-1-2-6.7. Clean coal technology -- Depreciation.

(a) As used in this section, "clean coal technology" means a technology (including precombustion treatment of coal):

(1) That is used in a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and

(2) That either:

(A) Is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or

(B) Has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989.

(b) The commission shall allow a public or municipally owned electric utility that incorporates clean coal technology to depreciate that technology over a period of not less than ten (10) years or the useful economic life of the technology, whichever is less and not more than twenty (20) years if it finds that the facility where the clean coal technology is employed:

(1) Utilizes and will continue to utilize (as its primary fuel source) Indiana coal; or

(2) Is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal;

after the technology is in place.

HISTORY: P.L.105-1989, § 3.

NOTES:

LexisNexis 50 State Surveys, Legislation & Regulations

Coal Processing & Power Generation

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Gross Plant	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940										
Depreciation (6.667%)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63										
Accum. Deprec.	63	126	189	252	315	378	441	504	567	630	693	756	819	882	945										
Net Plant	877	814	751	688	625	562	499	436	373	310	247	184	121	58	-5										
Gross Plant	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940
Depreciation (4%)	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Accum. Deprec.	38	76	114	152	190	228	266	304	342	380	418	456	494	532	570	608	646	684	722	760	798	836	874	912	950
Net Plant	902	864	826	788	750	712	674	636	598	560	522	484	446	408	370	332	294	256	218	180	142	104	66	28	-10

Note 1 - Figures are in millions

EXHIBIT ____

Kentucky Power Company

REQUEST

Refer to the Company's response to Sierra Club initial data request 1-17b and 1-17h. Direct Testimony of Ranie Wohnhas, page 14 line 22 to page 15 line 5 refers to the possibility that future increased EPA standards could "...cause operation of this unit not to be economically feasible in the future". With reference to the possibility of such future increased EPA standards response 1-17b states that the Company "...does not believe it is appropriate to assume an absence of any material risk of future environmental regulations."

a. Please confirm that these two statements indicate that the Company believes it is appropriate to assume there is a material risk of future environmental regulations that could cause operation of the Big Sandy Unit 2 not to be economically feasible in the future. If the Company cannot confirm this interpretation please explain why not.

b. If the Company believes it is appropriate to assume there is a material risk of future environmental regulations that could cause operation of the Big Sandy Unit 2 not to be economically feasible in the future, please explain why the Company did not analyze that risk per response 1-17h.

RESPONSE

a. The Company believes it is appropriate to assume there is risk of future environmental regulations that could cause operation of the Big Sandy Unit 2 not to be economically feasible in the future.

b. While the Company agrees it is appropriate to consider risk of future environmental regulations, it is difficult to quantify such risk from potential unknown requirements. However, the Company has proactively attempted to quantify such risk by including costs in analyses that are associated with current and potential EPA regulatory programs. In addition to the final CSAPR and MATS rules, analyses of Big Sandy Plant include potential cost implications related to the proposed 316(b) and CCR rules and the yet-to-be proposed Steam Electric Effluent Guidelines. Each of these programs could require installation of mitigation technology at Big Sandy Plant. In addition, the Company has for some time now included a carbon "tax" in its analyses as a proxy for some future regulation of greenhouse gas emissions. The timing of the applicability of such a proxy has changed as prospects for Green House Gas legislation have waned in the current US Congress.

WITNESS: Ranie K Wohnhas

SC EXHIBIT 7

EXHIBIT ____

Kentucky Power Company

REQUEST

Refer to the Company's response to Sierra Club initial data request 1-17j. If the Company expects to recover the total amount of all revenue requirements associated with Big Sandy unit from ratepayers, including all stranded investment, why is it concerned about the number of years over which it recovers that amount? (We recognize that the net present value of the total amount the Company would ultimately collect from ratepayers would be less if it collected the revenue requirements and stranded investment over a shorter number of years rather than a longer number of years).

RESPONSE

If the Company were allowed recovery of all costs associated with installing a DFGD on Big Sandy Unit 2 including any future stranded investment, then the Company would not be as concerned about the number of years in which it recovers those costs.

WITNESS: Ranie K Wohnhas

SC EXHIBIT 8

SC EXHIBIT 9

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

And

In the Confidential File Materials at the PSC

SC EXHIBIT 10

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

And

In the Confidential File Materials at the PSC

EXHIBIT ____

Kentucky Power Company

REQUEST

Please describe in detail (including age, year acquired, technology, and whether facility was operational) any natural gas-fired power plants that AEP or Kentucky Power has purchased since 2005?

a. For the natural gas-fired power plants AEP or Kentucky Power has purchased since 2005, were these plants purchased at or below the cost of new construction?

b. For the natural gas-fired power plant AEP or Kentucky Power has purchased since 2005, what was the process administered in the purchase of these plants? Was a request for quotes administered?

RESPONSE

Kentucky Power Company owns no gas-fired generation. Listed below are the gas-fired power plants purchased by AEP since 2005:

Waterford Generating Station -- The Waterford plant is an 821-megawatt, natural gas-fired, combined cycle plant located in southeastern Ohio. The plant began commercial operation in August 2003. AEP completed the purchase of Waterford Sept. 28, 2005, from an affiliate of Public Service Enterprise Group for approximately $220 million.

Ceredo Generating Station -- The Ceredo plant, located near Ceredo, W.Va., is a 505-megawatt, natural-gas, simple-cycle power plant. Designed and built for Columbia Energy by AEP's Pro Serv subsidiary, it was completed and began commercial operation in 2001. AEP completed the purchase of Ceredo on Dec. 15, 2005, from a subsidiary of Reliant Energy for approximately $100 million.

Darby Generating Station -- The Darby plant, located approximately 20 miles southwest of Columbus, is a 480-megawatt, natural-gas, simple-cycle power plant. The plant began commercial operation in 2001. AEP completed the purchase of Darby on April 25, 2007 from DPL Energy, LLC, a subsidiary of DPL Inc., for approximately $102 million.

SC EXHIBIT 11

Lawrenceburg Generating Station -- The Lawrenceburg plant, located adjacent to AEP's Tanners Creek Plant in Lawrenceburg, Ind., is a combined-cycle, natural-gas power plant with a generating capacity of 1,096 megawatts. The plant began commercial operation in June 2004. AEP completed the purchase of the plant May 16, 2007 from an affiliate of Public Service Enterprise Group for approximately $325 million.

Dresden Generating Station -- The Dresden plant, located near Dresden in east-central Ohio, is a combined-cycle, natural-gas power plant with a generating capacity of 580 megawatts. AEP completed the purchase of the partially constructed plant in September 2007 from Dresden Energy LLC, a subsidiary of Dominion for approximately $85 million. The plant began commercial operation in January 2012. Total costs for the plant were approximately $366 million.

a. The purchased facilities were "distressed." That is, the sellers were thought to be highly motivated because of high natural gas costs and a surplus of capacity. As a result, and although a formal study was not performed to determine the cost of new construction of the same facility, it is the Company's belief that the purchase price was at or below the cost of new construction.

b. In 2004, American Electric Power Company, Inc. ("AEP") system personnel on behalf of the AEP East system operating companies generally, and not any specific AEP operating company, launched an initiative to identify and evaluate existing "distressed" marketplace assets to determine if these assets could be acquired at a discount (when compared to newly-built generation) that exceeded the near-term carrying costs of these assets. Several facilities, which were either already in operation or under construction, and which were directly connected to AEP transmission system, as well as an asset relocation option, were identified for possible acquisition. AEP then pursued the acquisition of assets (note that in some instances, owners of assets contacted AEP directly regarding their interest in selling their assets to AEP) through bilateral discussions. The assets that were successfully acquired through this process are outlined in the response to AG 2-6.

A formal RFP for quotes was not administered by KPCo or AEP for potential additions of natural gas generation to AEP's Eastern Fleet.

WITNESS: Toby Thomas

EXHIBIT ____

Commonwealth of Kentucky

Before the Public Service Commission

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANTING OF A CERTIFICATE OF PUBLIC CONVIENENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES.	))))))))))	Case No. 2011-00401

Direct Testimony of
Jeremy Fisher, Ph.D.
Including Revised – Supplemental Pages

On Behalf of
Sierra Club

May 1, 2012

Public Version

SC EXHIBIT 12

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1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address and position.

A My name is Jeremy Fisher. I am a scientist with Synapse Energy Economics (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and four years of working within the energy planning sector, including work on integrated resource plans, long-term planning for states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates, the State of Utah Energy Office, the National Association of State Utility Consumer Advocates (NASUCA), National Rural Electric Cooperative Association (NRECA), the State of Alaska, the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Stockholm Environment Institute (SEI), and Civil Society Institute.

Prior to joining Synapse, I held a post doctorate research position at the University of New Hampshire and Tulane University examining the impacts of Hurricane Katrina.

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and an Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as **Exhibit JIF-1.**

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Kentucky Public Service Commission?

A Yes, I have. On September 16, 2011 I filed direct testimony in the joint application of Kentucky Utilities/Louisville Gas &Electric for a CPCN in similar dockets (2011-00161 and 2011-00162).

Please identify the Company's documents and filings on which you base your opinion regarding the Company's expectations for and treatment of environmental compliance costs affecting its fleet of coal plants.

A In addition to the Application for Certificate of Public Convenience and Necessity (CPCN) with accompanying witness testimony and appendices in this case, I have reviewed the following data prepared by Kentucky Power Company (KPCo) and American Electric Power (AEP) (the "Company", collectively):

- Select input and output data from the Strategist model as used by the Company in this docket;
- Input and output data from the Aurora model to the extent made available by the Company;
- Numerous spreadsheet workpapers supplied by the Company in response to discovery requests by Sierra Club, Staff, and KIUC.

- Other discovery responses filed by the Company to both Sierra Club and other parties.

Q Have you based your findings and opinions on the complete set of filings submitted by the Company?

A Yes, however, the Company's failure to timely respond to Sierra Club's data requests hindered our ability to determine whether additional information relevant to the Company's filing exists. In particular, Sierra Club received incomplete responses to initial data requests and only received complete responses on February 27th – four days prior to the original direct testimony deadline and more than two weeks <u>after</u> the filing deadline for supplemental discovery.[1] These initially withheld responses turned out to be quite crucial in our assessment of the Company's plan. It took the entirety of the last two weeks remaining to us to piece together how the Company arrived at its final conclusion. While the mechanism by which the Company arrived at its answer was eventually brought to light, the information in these files raises many more questions that should be fully explored. Without questioning motive, we have found numerous key assumptions obfuscated or incompletely explained. Therefore, I hesitate to say whether the information supplied by the Company to date presents a complete picture upon which the Commission and the parties can evaluate the Company's filing.

Q What is the purpose of your testimony?

A My testimony details and evaluates specific components of the Company's analysis supporting this CPCN application. My testimony reviews both inputs assumptions and the outcomes from two models used by the Company to support this filing: STRATEGIST ("Strategist") and Aurora^{xmp} ("Aurora"). I approach four significant areas of concern within the Strategist model and supporting

[1] The Company apparently filed the supplemental response to 1-69 "containing detailed back-up to Exhibit SCW-4A through SCW 4-E" on Wednesday, February 22nd, but sent the files to Sierra Club analysts by second-day delivery. This mailing was not received until the start of business on Monday, February 27th.

workpapers: which capital costs are utilized in the model, how fixed operating and maintenance costs are portrayed in the model, the treatment of off-system sales from KPCo, and the adequacy of the sensitivities explored using Strategist. For both the Strategist and Aurora models, I challenge the assumption that the Company's carbon dioxide (CO_2) price forecast represents a standard in the industry or a reasonable assessment of CO_2 price risk. Finally, I assess the utility of and assumptions behind the Aurora model, challenging internal inconsistencies between stated input assumptions and those actually used in the model, the derivation of fundamental assumptions and errors in those derivations, the output of the model as compared against the Company's other modeling mechanism, and the use of the model in this filing.

My testimony relies on Strategist modeling conducted by my colleague Ms. Rachel Wilson, who has also sponsored testimony in this docket, and supports the conclusions drawn by my colleague Mr. Hornby. The calculations that I present in this testimony are my own.

Q Are you filing any exhibits with this testimony?

A I have attached the following exhibits to this testimony:

- **Exhibit JIF-1:** Curriculum Vitae;
- **Exhibit JIF-2:** Relative cumulative present worth of Options 1, 2, and 4A under Company and corrected assumptions;
- **Exhibit JIF-3:** Tables indicating the CPW of Options 1-5 under Company assumptions and corrected assumptions;
- [redacted];
  [redacted];

[redacted]

- **Exhibit JIF-7**: Comparison of CO_2 price forecasts government entities, other electric utilities, industry groups, and Company;
- **Exhibit JIF-8**: Synapse CO2 price forecast paper, February 2011.
- **Exhibit JIF-9**: Company results from Strategist with ranges from Aurora model.
- **Exhibit JIF-10:** Differences between Aurora and Strategist outcomes; differences between Aurora and Strategist variables.
- **Exhibit JIF-11**: Comparison of CPW cost components between Strategist and Aurora.
- **Exhibit JIF-12**: Correlations for Aurora from Company in testimony, as used in Aurora, and as derived from US datasets.

2. Summary and Conclusions

Q In your opinion and according to the documents you have reviewed, does the Application submitted by the Company in this proceeding merit the requested Certificate of Public Convenience and Necessity and associated Environmental Surcharge?

A No, it does not. I have found numerous errors, inconsistencies, and flaws within the workbooks supporting the application rendering the Application inadequate and incomplete. The application does not support the Company's contention that the environmental retrofits at Big Sandy 2 are the least cost solution for ratepayers. In attempting to reconstruct the Company's analysis supporting its contention, I have found multiple circumstances where specific errors or flaws in the analysis or underlying assumptions have biased the results towards favoring the retrofits. Correcting these sometimes simple errors leads to the conclusion that retrofitting Big Sandy 2 is [redacted] the least economical choice for Kentucky Power Company's ratepayers.

In short, the Company has not demonstrated that the retrofit of the Big Sandy 2 unit is warranted given the availability of other, lower cost options for the Company.

Q Are you suggesting that the decision to retrofit the Big Sandy 2 unit is based on an erroneous analysis?

A In part, yes. My colleague Mr. Hornby briefly characterizes some of the changes made in the Company's analysis over the last few months of 2011. Up through October of 2011, the Company was still indicating to shareholders that the Big Sandy 2 unit would be retired because it was not economic to install a flue gas desulfurization (FGD or DFGD) system.[2] One month later, however, the Company indicated to investors that it would retrofit the Big Sandy 2, not retire it.[3] In at least six presentations from November through December 2011,[4] including some after the Company had requested nearly $1 billion from this Commission in this CPCN application,[5] the Company continued to tell investors that the retrofit would cost $525 million.[6] While the Company attributes at least one slide (and presumably the five others like it) to a "scrivener's error," errors of the same magnitude are found throughout the analysis underlying this application.

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[2] Attachment to response to Sierra Club DR 1-1. "ISI Meeting Handout" (October 6, 2011) slide 11, and response to Sierra Club DR 2-11. "Although the Company was still reviewing all of the alternatives as of this date [Oct 6, 2011], Big Sandy Unit 2 was then being shown as a retirement."

[3] Attachment to response to Sierra Club DR 1-1. "Morgan Stanley Office Visit" (November 17, 2011) slide 22, and response to Sierra Club DR 2-12. "In November 2011, installation of a DFGD on Big Sandy Unit 2 was the alternative that had been chosen by the Company."

[4] Attachment to response to Sierra Club DR 1-1 "2011 Fact Book 46th EEI Financial Conference" (Nov. 6, 2011); "46th EEI Financial Conference Handout" (Nov 7-8, 2011); "Morgan Stanley Office Visit" (Nov. 17, 2011); "Utilities Week Investor Meeting Handout New York" (Nov. 29-30,2011); "Wells Fargo 10th Annual Pipeline, MLP & Energy Symposium Handout" (Dec 7, 2011); "Goldman Sachs 6th Annual Clean Energy & Power Conference" (Dec. 9, 2011);

[5] Initial CPCN filing on Dec 5th, 2011.

[6] Attachment to response to Sierra Club DR 1-1. "Goldman Sachs 6th Annual Clean Energy & Power Conference" (December 9, 2011) slide 20, and response to Sierra Club DR 2-13. "In reviewing Slide 20 of the Goldman Sachs 6th Annual Clean Energy and Power Conference (December 9,2011), investors would have noted that the high end cost for the Big Sandy 2 FGD was stated to be $525 million."

[redacted]

Based on evidence provided by the Company, the cost of the FGD retrofit has remained unchanged since at least June 2011.[7] While the Company has not indicated when it received the estimated cost of replacement natural gas combined cycle (NGCC) from Sargent and Lundy (S&L), it appears that this estimate was available to the Company in mid-2011 as well.[8] Therefore, it is unclear how or why the Company's assessment of the relative economics of retrofitting or replacing the Big Sandy 2 unit changed just one month before this application was filed.

Other errors and inconsistencies in the Company's Strategist analysis, such as the allocation of all off-system sales for ratepayer benefit (rather than as currently split with shareholders), a surprising drop in fixed O&M costs for the FGD unit in 2030, and an extremely low "base" CO_2 price all appear to favor the Company's retrofit decision. Further, the sensitivity commodity prices used by the Company fail to allow for a reasonable exploration of actual risk.

Inputs into the Aurora analysis, used by the Company as a form of risk assessment, contain significant calculation errors and are inconsistent with direct testimony filed by the Company in this case.

[7] See response to Sierra Club DR 2-10e.

[8] Information embedded in the file "Big Sandy CC Brownfield Build_Option 2 S&L Client Version DETAIL.xls" provided in response to Sierra Club DR 1-69 in supplemental response indicates that it was "last printed" in May of 2011.

Q **What is your overall finding?**

A When we correct knowable errors within the Company's fundamental Strategist analysis, each and every alternative explored by the Company – repowering Big Sandy 1 as a natural gas unit, replacing the Big Sandy 2 unit with a brownfield NGCC, or purchasing market power to 2020 to 2025 – are all more cost-effective than the FGD retrofit [redacted].

Figure 1 below (also **Exhibit JIF-S2 Supplemental)** shows the total cumulative present worth (CPW) of Options 1, 2, & 4A under the Company's "BASE" assumptions on the left, and the gap that appears to render Option 1 least cost of these three options. On the right, I show the results of our analysis [redacted], an allocation of off system sales (OSS) to shareholders, and running the model under a low-bound carbon dioxide cost (CO_2) representative of that used by other utilities and organizations.

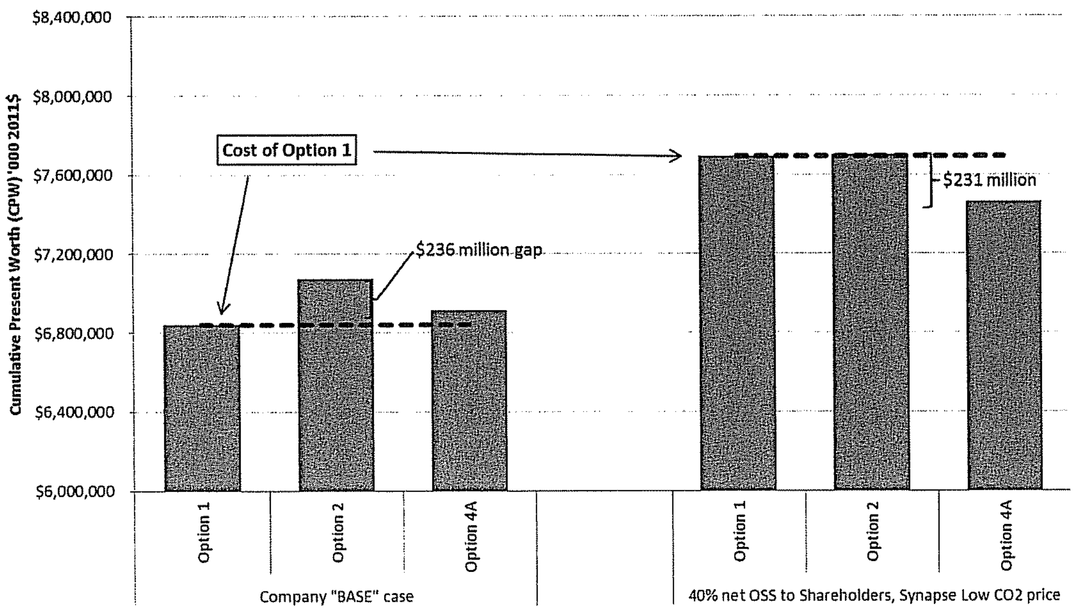

Figure 1. Cumulative present worth (CPW) of Options 1 (retrofit), 2 (NGCC replace in 2016), and 4A (market purchase to 2020) under Company Base assumptions (left) and Synapse revised assumptions and corrections (right) (REVISED). See text for details.

Q Would you give an overview your testimony structure?

A My testimony largely supports the overarching testimony of Mr. Hornby, and thus is divided into discrete segments exploring errors and uncertainty in both the Strategist model and the Aurora model.

- In **Sections 3-7**, I discuss a series of concerns with the Company's Strategist modeling, [redacted] fixed O&M costs, off-system sales, and the commodity pricing sensitivities used by the Company.
- In **Section 8,** I challenge the reasonableness and basis of the Company's CO_2 price forecast, and provide alternative options for consideration.
- In **Sections 9-13**, I examine the Company's Aurora model and its inputs, to the extent provided by the Company. I discuss my concerns with the overall Aurora results, the lack of transparency associated with the use of this Aurora model, errors and inconsistencies in the underlying correlations used in this analysis, and deep concerns about the use of this model to support this particular filing.
- Finally, **Section 0** summarizes my conclusions and recommendations.

3. <u>Strategist Concerns – Overview</u>

Q Please describe how the Company has used Strategist to support this filing.

A An analysis based on output from the Strategist model forms the basis of the Company's decision to retrofit the Big Sandy 2 unit and directly support Exhibit SCW-4 in Mr. Scott Weaver's direct testimony. My colleague Ms. Wilson discusses in depth how the Company used the Strategist model itself in this proceeding. I have evaluated the post-model analysis conducted by the Company and discussed by Mr. Weaver.

My understanding is that the Company has developed a number of input assumptions used to drive the Strategist model. As Ms. Wilson describes, for the purpose of this filing, the Company does not appear to have used the optimization capability of Strategist, instead "locking in" all resource choices and, in effect, using Strategist as a production cost model. Certain outputs of the Strategist model, specific to the KPCo system, are then brought into what I will call the "Company Strategist Compilation Workbook," a separate analysis that calculates the cumulative present worth (CPW) of each option.[9] These CPW values are then used in Exhibit SCW-4.

The Strategist model is used to compute annual fuel costs, contract and market costs and revenues for *energy*, fixed and variable O&M costs, and total emissions costs. Although Mr. Weaver states in his direct testimony that fixed carrying charges and capacity sales/purchases are also "model outputs," this is not strictly the case. Both capital carrying charges and capacity sales/purchases, as used in this filing, are calculated completely externally to the Strategist model in the Company Strategist Compilation Workbook.

Also of note is that fixed O&M expenses are input into the Strategist model and passed, unaltered, out of the Strategist model; because the Strategist model does not optimize scenarios, these fixed O&M charges are effectively calculated completely externally to the Strategist model as well.

Q Which elements of the Strategist model, as used in this filing, are of concern?

A Ms. Wilson describes specific elements of the Company's use of the Strategist model that are of concern. I will focus on inputs to the model, the Company Strategist Compilation Workbook, and areas of concern that can be tested quickly through the Workbook. In particular, I have five areas of concern that are important in this CPCN application:

1. The treatment of off-system sales out of the KPCo system (Section 4)

[9] These workbooks were made available in supplemental discovery responses to Sierra Club DR 1-69. There is a separate workbook for each Option under each market commodity pricing scenario for a total of 25 workbooks (as used in this filing).

[redacted]

3. Inconsistent behavior or use of fixed O&M costs as input into the Strategist model (Section 6),
4. The appropriateness of the "commodity price" sensitivities used by the Company (Section 7) and
5. The Company's reference carbon dioxide (CO_2) price is far lower than reference prices used by any other source cited by the Company (Section 8)

It is my opinion that, had the Company correctly portrayed the current split in off-system sales between ratepayers and shareholders [redacted] used a CO_2 price consistent with other utilities, consultants, and agencies, or any combination thereof, the outcome of this analysis would have been very different, and not favorable to the retrofit.

4. Strategist Concerns: Off System Sales

Q What is your concern with off-system sales as depicted in the Company Strategist Compilation Workbook?

A My colleague Mr. Hornby addresses whether off system sales revenues are appropriately allocated in this CPCN to the correct parties. As he notes, KPCo currently allocates 40% of off system sales (OSS) revenue to shareholders, not ratepayers. Presuming that the Company is presenting the Big Sandy 2 retrofit as the least cost alternative for ratepayers rather than for shareholders, one would presumably review the benefit for ratepayers – not the Company (i.e. shareholders). In the current modeling structure, the Company appears to have allocated all OSS revenues back to ratepayers, rather than splitting these revenues with shareholders.[10]

If the Company expects that the current 40-60 revenue split will continue through the analysis period, then the expectation of ratepayer benefit assumed in the modeling should be different.

Q To what extent would sharing off-system revenues with shareholders impact the net outcome of the Strategist analysis?

A I tested how the split in OSS revenues might affect the outcome of this analysis. Using the Strategist output of market sales out of KPCo,[11] I deducted 40% of the market sales (net of the variable cost of production) from the KPCo system on an annual basis, and, following the Company's method for calculating the total cumulative present worth (CPW), subtracted the remaining revenues from the stream of costs and calculated a new CPW.

The result of allocating 40% of OSS revenues to shareholders drives up the cost seen by ratepayers – but drives it up faster in those scenarios where KPCo has greater off-system sales, in this case Option 1. The CPW of Option 1 rises by about $100 million, while the other scenarios rise by about $80 million. Ultimately, the net effect is to narrow the gap between Option 1 and the other alternatives – and makes the market purchase options more attractive, even tipping the balance of Option 4A (market purchases to 2020) into a net benefit relative to the retrofit (see

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[10] Received from the Company in response to Sierra DR 1-1, the 2011 EEI Fact Book (Nov. 2011) the Company reminds investors that Kentucky has an OSS sharing mechanism allocating 60% of OSS to ratepayers (p69).

[11] Generation and Fuel Module System Report from Strategist, line "Econ Energy Sales" in KPCO section.

Table 1 below; also in **Exhibit JIF-S3A**). Option 4B (market purchases to 2025) continues to remain less expensive than Option 1.

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Table 1. Cumulative present worth of revenue requirements (M 2011$): Reanalysis with adjusted off-system sales (revised).

Cumulative Present Worth of Revenue Requirements (M 2011$)
Re-Analysis with Adjusted Off System Sales

	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #3 BS1 Repower	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Adjusted Off System Sales					
CPW	6,943	7,154	7,171	6,993	6,862
Net benefit of retrofit (CPW)		211	228	49	(81)

[redacted]

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6. STRATEGIST CONCERNS: FIXED O&M COSTS

Q What is your concern with the fixed operation and maintenance (O&M) costs used in the Company's model?

A The stream of fixed O&M costs in Option 1 (the retrofit case) drops markedly from 2030 to 2031 by about $36 million per year (nominal, or $27 M 2010$) and maintains at this lower value through the remainder of the analysis period.[25] We can trace this discrepancy back to the input (and output) for the Big Sandy 2 FGD from the Strategist model where fixed O&M costs for this single unit drop by $45 million (nominal, or $33 M 2010$) in 2030.

Q Would such a drop in fixed O&M costs be expected if the unit were continuing to operate in 2031 as it did in 2030?

A I can think of no reasonable explanation why fixed O&M costs, usually representing <u>ongoing</u> capital expenditures and maintenance activities, should decline so markedly in 2031.

[25] In the year 2040 fixed O&M appears to takes very high end-effects value as discussed by Ms. Wilson.

Q Is the drop in expected fixed O&M costs important in the outcome of the model?

A Yes. If the pre-2031 fixed O&M costs were carried through the end of the analysis period (2031-2039), we would expect the 2011 cumulative present value (CPW) of the retrofit to increase by about $69 million (2011$).

Q Can you explain why the fixed O&M costs may have this behavior?

A No, but I can put forward a hypothesis. I suspect that the Company has included a discrete 2016 capital expense as part of the fixed O&M stream of costs. A capital cost amortized over 15 years using the Company's levelized carrying charge mechanism would appear as a flat increase in nominal dollars over a 15 year period (i.e. ending in 2030). Comparing the stream of fixed O&M costs input into the Strategist model with fixed O&M costs apparently input into the Aurora model,[26] I note that the Strategist model assumes an additional $34 million each year (flat in nominal terms) from 2016 to 2030.

This discrepancy is somewhat corroborated by the Company's response to KIUC DR 2-2f with the statement that "a component of the fixed o&m [sic] is ongoing capital costs which are recovered through an annual carrying charge." While I believe that there is likely an additional capital cost "that is recovered through an annual carrying charge" for 15 years, I find it difficult to believe that this increase represents "ongoing capital costs" (emp. added) as those would likely carry through the full analysis period (presuming that the FGD remains in operation).[27]

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[26] From file Sierra DR 2-34a "sc_KPCo 2011 3 Plans Unit Data_10_10_11_confidential.xls"

[27] Company response to KIUC DR 2-2f indicates that one should "see the accompanying CD to the response to KIUC 2.2(a) for all assumptions and source documents." While the attached files are large, they does not present the breakdown of either variable or fixed O&M costs pertinent to KIUC's request, or the reasoning behind the changes in the fixed O&M values over time.

7. <u>STRATEGIST CONCERNS: INSUFFICIENT FUEL PRICE SENSITIVITIES</u>

Q Did the Company examine any risk sensitivities in the Strategist model?

A Ostensibly, yes, but the sensitivities used by the Company are not able to adequately explore a reasonable range of future price risks. The Company runs their model through four sensitivities, described very briefly below:

- A "higher" band of prices in which fuel costs (both gas and coal) are increased by 16-20% and CO_2 prices are effectively unaltered;[28]
- A "lower" band of prices in which fuel costs (both gas and coal) are decreased by 11-12% and CO_2 prices are effectively unaltered;
- An "early carbon" scenario in which carbon prices start in 2017 instead of 2022 but are only about 80¢ higher (real 2011$);
- A "no carbon" scenario in which there is no carbon price and fuel prices are effectively unchanged (gas prices are reduced by 6%).

Q What is problematic about these sensitivities?

A While I appreciate that the Company is attempting to examine both the impact of changing fuel prices and uncertainty in CO_2 prices, these alternative futures are insufficient sensitivities, particularly in stress-testing the effectiveness of continuing to operate a coal-fired power plant versus replacement with a natural gas portfolio. Useful sensitivities push to reasonably likely futures that <u>are substantively different from each other</u>. In this case, however, I would not expect any of the sensitivities evaluated by the Company to result in dramatically different results.

For example, for both the "high band" and "low band" options, coal and natural gas prices move in the same direction almost perfectly – meaning that we would generally expect the results of these analyses to show about the same level of

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[28] CO2 prices are increased by 30¢ (in real 2010$)

differentiation from each other. In particular, when the all-in variable cost of a new natural gas fired CC is quite close to the all-in variable cost of the coal retrofit, as is the case here,[29] changes in the cost of coal and the cost of natural gas will not really differentiate the costs of the Options – if it is assumed that coal and natural gas prices will both move about the same amount in the same direction.

The "no carbon" scenario simply bolsters the Company's standing position. The "early carbon" scenario does impose new costs between 2017 and 2022 for five years of additional carbon pricing; but at the low prices assumed by the Company, these five years result in fairly small differentiations for such a significant policy.[30]

Q Has the Company explored more functionally useful sensitivities in Strategist?

A No, they have not. KIUC asked the Company in DR 2-3 if the Company had run a scenario in which lower prices for gas were run against higher prices for coal; the Company responded that it had not.

Q Why did the Company choose not to run low gas / high coal?

A The response to discovery, written by Mr. Karl Bletzacker, states that "the Company determined it was unnecessary to do so because coal and natural gas prices have historically been correlated, that is, coal and natural gas prices rise and fall in unison…" This statement appears to contradict the testimony of Mr. Scott Weaver, who shows explicitly in his Aurora "Assumed Variable Correlations" table (Exhibit SCW-1, Table 1-4) that prices for natural gas and

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[29] In the base case, differentiated by about \$5-\$7/MWh in 2010\$

[30] For the first years of this analysis prior to the start of carbon pricing in 2022 (i.e. 2011-2021) the difference in CPW of Option 1 is about \$300 million between the early carbon and base commodity price scenarios. Conversely, the difference in CPW of Option 2 is about \$240 million over that same time period (between the early carbon and base scenarios). Pushing up the Company's carbon price by five years only results in a \$60 million dollar shift between Options.

coal are <u>not</u> correlated.[31] I agree that the price of natural gas and coal have not been correlated (in real dollar terms).

Q What is your recommendation?

A In evaluating this CPCN, running scenarios in which the price of fuels are not correlated would be an important and illuminating mechanism of evaluating the risk of either a retrofit or retire decision.

8. REASONABLENESS OF CO_2 PRICE AND RISK

Q Did the Company consider the potential for costs associated with carbon dioxide emissions?

A To a limited extent, yes. In the base case, and in four of five "pricing scenarios," the Company utilized a price for carbon dioxide (CO_2) emissions.

Q Why, then, are you concerned about the Company adequately accounting for potential carbon legislation?

A The price employed by the Company for CO_2 emissions does not represent any form of an effective or likely carbon policy but rather a token price that is never increased.

Q What do you mean by a "token price" for CO_2?

A I define a token price as a cost for no other purpose than simply imposing a cost – a price that neither changes dispatch decisions or build decisions – i.e. has no impact at either operational or build margins.

Q What has the Company used as a CO_2 price in this proceeding?

A In the base case, the Company's CO_2 "Base" price starts at about $15 per metric tonne and escalates about 1.3%, or slower than inflation. In real 2010$ per short

[31] The non-relationship between historic movements of the price of natural gas and the price of coal is consistent between Mr. Weavers' table, US historic records and the UK futures examined by Mr. Weaver.

ton,[32] this price starts at $10.82 and holds essentially flat. The "early carbon case" starts five years earlier and is about 80¢ cents higher than the base case in real 2010$.

Exhibit SCW-2 shows a slightly higher value of CO_2 for the "high band" and "low band" sensitivities; a price difference that amounts to about 30¢ higher than the base case in both sensitivities. However, this is inconsistent with the data from the Strategist model. An examination of the data underlying SCW-4A[33]indicates that the CO_2 price in the higher and lower bands are identical to the base case.

Q How does this compare to other CO_2 price forecasts used by other utilities?

A Of the numerous recent CO_2 price forecasts that I have reviewed, this is the lowest I have seen used for "reference case" purposes.[34]

Synapse has collected 22 different utility IRP and utility docket documents from a very diverse set of utilities operating all over the U.S.[35] These IRPs, all published in 2010 or 2011, all provide estimates for CO_2 prices at some time within the 2012-2040 planning horizon used by AEP. With the exception of two IRPs and case documents that did not use a CO_2 price at all,[36] all of the reference CO_2 price forecasts used by other utilities are higher than that of the Company. Indeed, there are no other utility forecasts that fall in real terms.

Most other CO_2 price trajectories that I have reviewed assume a particular purpose – i.e. the mitigation of greenhouse gas emissions to prevent or slow the

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[32] About 1.1 short tons per metric tons; derived cumulative inflation rate from natural gas prices in nominal and real dollars as presented in Sierra DR 1-69 "Ex. SCW-2 (L-T Commodity Price Fcst).xls" to convert to real 2010$.

[33] See Staff 1-48 "Staff_1-48_(Ex SCW-4B-High Pr Eval Detail).xls", "Staff_1-48_(Ex SCW-4C-Low Pr Eval Detail).xls", and files associated with the "detailed back up files for SCW-4", including e.g. FT-"Higher Band 2-Pgrs\Levelized Retrofit Under FT_CSAPR_HIGH_BAND.xls"

[34] With the exception of the zero price assumed by another Kentucky utility in Cases No. 2011-00161 & 00162.

[35] See Exhibit JIF-5E for references

[36] Platte River Power Authority (Colorado, 2012) calculated a carbon mitigation curve (i.e. prices at which carbon reductions could be obtained by changing or building different resources), but did not provide an explicit price forecast. KU/LGE in KPSC Case No. 2011-00140 (2011) did not utilize a CO_2 price forecast.

pace of climate change. The basis of such prices is the concept that in order to eventually reach lower levels of CO_2 emissions, the effective price on CO_2 would have to rise over time, obtaining cumulative reductions in emissions by providing an incentive to mitigate at the lowest cost – essentially slowly moving up the supply curve of emissions reductions potential.

In contrast, the Company's price forecast appears to reflect a fairly cynical view that while a government entity might eventually impose a fee on carbon emissions, the political will to either increase or cease the fee will leave the price at a stalemate and thus achieve very little at all. This assumption is not shared by other utilities.

Q Has the Company reviewed other CO_2 price forecasts?

A Sierra DR 1-45 states that the "carbon dioxide price (CO2)… reflect[s] a national carbon tax and an industry consensus view." The response then lists a wide variety of stakeholders that shape the Company's view of the long-term forecast.

Q How does the Company's forecast hold up against the views of other "stakeholders" as listed in the discovery response?

A Many of the stakeholders listed therein do not actually provide forecasts (such as the trade press Coal Daily or Coal Weekly, or even some of the key organizations listed (such as NERC and FERC). Of those that I am aware of that do produce CO_2 price forecasts, their CO_2 trajectories are universally higher than those used by the Company here. For example:

- **Industry Groups** – Edison Electric Institute: EEI produced an assessment of recently promulgated and proposed environmental regulations (January 2011)[37] and included two CO2 prices, both of which are significantly above the Company forecast (see **Exhibit JIF-7A**).

[37] Provided in response to AG discovery request 1-14 as Attachment 16. CO_2 assumptions on page 50.

- **Government Agencies** – EPA and the US DOE Energy Information Administration have both produced estimates of the carbon price that would be realized from proposed federal legislation. These are all significantly above the Company forecast prices (see **Exhibit JIF-7A**). To my knowledge, NERC and FERC do not produce CO_2 price forecasts.[38]

- **Energy Companies** – Reference case CO_2 prices from 20 electric utilities, including Duke (SC-2011), TVA (TN/KY-2011), Ameren (MO-2011), Southern Company (GA-2011)[39], and Sunflower (KS-2010) amongst others are charted in **Exhibit JIF-7B**. Each and every trajectory charted here is higher to significantly higher than the AEP/KPCo forecast.

- **Third Party Consultants** – There are numerous third party consultants who have produced forecasts for CO_2 prices. Synapse Energy Economics, my firm, produced a CO_2 price forecast in early 2011. I have produced these forecasts in **Exhibit JIF-7C** also showing the range (in the lighter bar) of reference forecasts used by other utilities. I have attached the paper supporting the Synapse CO_2 price forecasts in Exhibit **JIF-8**.

Q Why are there two different AEP trajectories plotted in Exhibit JIF-7C?

A The Company provided, in Sierra DR 1-69 a file that appears to have commodity price assumptions from August of 2011,[40] including a CO_2 price forecast. [redacted]

[38] NERC specifically does not review the impact of CO2 regulations in its late 2010 reliability assessment (available as response to AG discovery request 1-14 in Attachment 9)

[39] The starting point for the Georgia reference case is public, but the trajectory is confidential.

[40] In August 2011 the Company was still announcing that the Big Sandy 2 unit would be retired.

Q Can you describe how the Company's CO_2 assumed reference and range of CO_2 prices compare to those of other electric utilities in the US?

A I have charted the low, high, and (if multiple forecasts were given) average levelized cost of CO_2 (2015-2030) from 16 utilities, Edison Electric Institute (EEI), the Eastern Interconnect Planning Collaborative (EIPC) and forecast prices from my firm Synapse, in the figure below (also attached as Exhibit **JIF-7D**).[41] The reference case in this CPCN (the last column) is the lowest non-zero price given and, aside from those utilities that only give a single value, just about the narrowest range of prices as well. The AEP (8/2011) price that is second to last represents the cost assumed by the utility in the preliminary analysis of Big Sandy 2 in August of 2011.

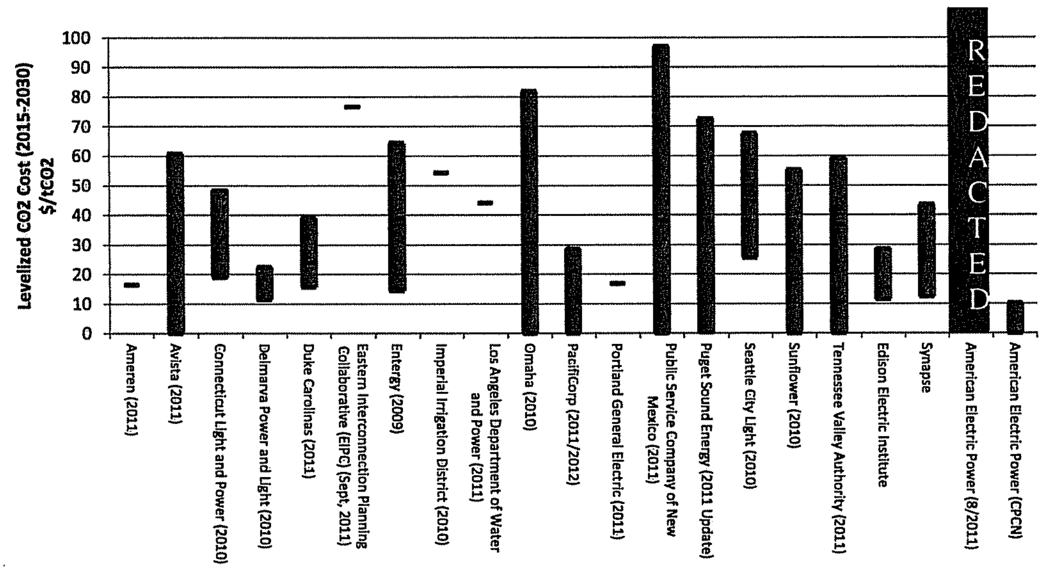


Figure 4. Low, high and average CO_2 prices given by different utilities in IRP & CPCN from 2010-2011. The AEP forecast for this CPCN is the final bar on this chart.

Q Have you evaluated how a more reasonable CO_2 price could impact the Company's decision to retrofit versus retire the Big Sandy unit?

Yes. Ms. Wilson conducted a re-analysis of the Company's Strategist base commodity price run, substituting the lowest CO_2 price forecast from my firm,

[41] Range given when a utility has produced or used more than one forecast. The average is given only if a utility has produced or used three or more forecasts.

Synapse (see **Exhibit JIF-7C and JIF-8**). The Synapse forecast was produced in February of 2011, and represents the marked uncertainty in how and when greenhouse gas prices might apply.[42] The forecast is a public document explaining background, state and regional initiatives, analytical estimates, and the recommended Synapse 2011 CO_2 price forecast for planning purposes.

For the purposes of this case, Ms. Wilson tested three of the Options (retrofit [1], NGCC replacement [2], and market purchases to 2020 [4a]) using the Synapse Low CO_2 Price Forecast. This CO_2 price starts at $15/ton (2010$/short ton) in 2020 and climbs to $45/ton by the end of the 2040 analysis period.

The Synapse Low forecast does <u>not</u> represent the Mid, or expected case, according to the Synapse paper. Rather, it represents what the organization considers the lowest reasonable bound for a CO_2 price forecast (both low in price and late in start).

The Synapse Low case is, for example, consistent with forecasts from Ameren (MO) in 2011 and Duke (SC) in 2011, but is below TVA's estimates, and well below estimates from Nebraska, Kansas, Delaware, Idaho, and Oregon.

Q Does using a reasonable Low CO_2 price forecast substantively change the outcome of this analysis?

A Yes, it does. Simply shifting the CO_2 price forecast to a low-range forecast consistent with the low end of forecasts from other utilities and organizations renders the retrofit of the Big Sandy 2 unit essentially a wash with the NGCC replacement in 2016 (Option 2) and far less economic than market purchases to 2020 (Option 4A).[43] **Error! Not a valid bookmark self-reference.**, below (**Exhibit JIF-3D**), shows the difference between the Company's base case run and a modified CO_2 price run with other Company assumptions intact.

[42] Early prices might be realized by rapid action starting after the next session of Congress, or if the EPA acts to regulate CO_2 emissions independently of legislative action. Late prices (2020) might represent an additional presidential term without either administrative or legislative action.

[43] We did not test, but assume that market purchases to 2025 (Option 4B) would continue to fare well in this analysis, and that Option 3 (repowering Big Sandy 1) would probably fare on par with Option 2.

Table 4. Cumulative present worth of revenue requirements (M 2011$): Reanalysis with Synapse Low CO_2 price

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO_2	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #4A Market to 2020; NGCC in 2020
Company Assumptions			
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price			
CPW	7,643	7,665	7,412
Net benefit of retrofit (CPW)		22	(230)

[redacted]

[redacted]

[redacted]

If we adjust the off-system sales revenue to reflect 40% sharing with shareholders as currently allocated from KPCo, the answers adjust again and even further favors either Option 4A or Option 2, as shown in

Table 6 (Exhibit JIF-S3F Supplemental), below.

Table 6. Cumulative Present Worth (CPW) under Company CO_2 assumptions and Synapse Low CO_2 price, capital cost corrected and adjusted for off-system sales sharing (revised 2).

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO2 & Adj. Off-System Sales			
<u>**0**</u>	<u>**Option #1**</u> Retrofit Big Sandy 2 w/ FGD	<u>**Option #2**</u> NGCC Replacement	<u>**Option #4A**</u> Market to 2020; NGCC in 2020
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
<u>**Synapse Low CO2 Price & Adjusted Off-System Sales**</u>			
CPW	7,694	7,702	7,462
Net benefit of retrofit (CPW)		9	(231)

Q **What CO_2 price trajectory do you recommend?**

A In large decisions where long-term CO_2 emissions are a tangible risk, it is incumbent on the Company to test a wide and reasonable range of CO_2 prices designed to bound the feasible risk faced by their ratepayers. As a reasonable starting point, I would recommend using the range provided in the Synapse 2011 CO_2 price forecast, using something akin to the Synapse Mid case as a reasonable reference. This price starts at $\$15/tCO_2$ in 2018 and rises (in real 2010$) linearly to $80 in 2041, and holds at that price indefinitely.[44] The "low" bound starts at $\$15/tCO_2$ in 2020 and rises at a slower pace, reaching $60 in 2050, while the "high" bound also starts at $15 but at 2015 and reaches the $80 saturation point in 2030. It may be reasonable to explore a complete absence of CO_2 price as one possible scenario (representing an inability to muster the political will to mitigate climate change), but I think this outcome over the next three decades is extremely unlikely.

[44] Synapse has assumed that $80 represents a broad-scale abatement price at which emerging technologies (such as carbon capture and sequestration) might become cost effective, thus potentially saturating the market.

Recalling that we have only tested the very lowest bounds of CO_2 prices in this re-analysis, I would expect that any higher prices would result in an even further economic advantage for Options 2 and 4A over the Big Sandy 2 retrofit.

9. <u>AURORA CONCERNS: OVERVIEW</u>

Q How did the Company use Aurora^{xmp} in this proceeding?

A In this proceeding, the Company has used Aurora to evaluate how uncertainty in several key variables, such as fuel and emissions prices, as well as demand and electricity market prices, might influence the relative risk of four options – retrofitting Big Sandy, replacing or repowering the unit in 2015 (Options 2 & 3, respectively) or replacing the unit in 2025 (Option 4b). The Company did not use Aurora to evaluate Option 4a, purchasing market power through 2020.

Because the Company used the model to drive a stochastic analysis, Aurora potentially offered the Company the opportunity to evaluate a range of uncertain futures simultaneously – in essence replacing the function of running Strategist through multiple pricing, or commodity, scenarios.

Q What results did the Company draw from the Aurora analysis in this proceeding?

A This is unclear. On pages 46-48 of his testimony, Mr. Weaver discusses <u>only</u> the metric of Revenue Requirement at Risk (RRaR), which is effectively the width of the uncertainty band around the middle, or median, answer. Mr. Weaver does not suggest in his written testimony that the differences between the median costs projected by the Aurora model should be used to evaluate the relative cost effectiveness of each option. In Sierra DR 1-68, Mr. Weaver appears to further re-enforce the statement that Aurora model is not designed to measure the relative economic merit of the options, but "is used to measure the relative risk inherent in a resource portfolio," by which I understand him to mean that it should be used to measure the relative risk inherent in any given resource portfolio, rather than the relative economic viability of the different scenarios. The relative economic viability measures an expected outcome, while the "risk inherent" measures the uncertainty associated with any given scenario.

Q Mr. Weaver cites Exhibit SCW-5 as an "optical and tabular summary of those results." What is your impression of this Exhibit?

A I read Figures 5-1 and 5-2 in SCW-5 very differently than described by Weaver in his written testimony. The first and most obvious point that stands out from this graphic is that the median of Option 1 appears to be much lower in "Cumulative Present Worth" than the other three Options modeled here. Indeed, the exhibit then shows, in tabular form, the "delta" (or difference) in alternative Option costs relative to Option 1, and suggests a consistently large benefit in pursuing the retrofit.

Q What do you recommend in regards to Mr. Weaver's Exhibit 5?

A Whether in error or purposefully, the Company misrepresents the point and potential value of the Aurora analysis, which is to estimate the uncertainty associated with the economic outcome of their various options, rather than the absolute outcome.

I recommend that, if the Company chooses to pursue the use of the Aurora model for uncertainty analysis, that the Company withdraw Exhibit 5 and replace it with an exhibit (graphical, tabular or both) that correctly represents the uncertainty bounds and RRaR, rather than absolute outcomes as shown here.

However, there are sufficient concerns with how the Aurora model has been used in this proceeding to warrant disregarding the Aurora analysis in its entirety.

Q Do you have a fundamental objection to the use of this type of model for planning purposes?

A No, I do not. Conceptually, there is value in being able to evaluate a wide range of uncertainties simultaneously. In particular, this type of evaluation could, and should, be used to determine just how much any Option differs from another – i.e.

if a separation of millions of dollars in cumulative present worth (CPW) is significant or insignificant.

Generally speaking, I applaud the use of multiple models to converge on a robust answer, particularly in the face of uncertainty, and I would encourage the Company to continue developing the use of other models to support decision-making.

However, I have significant concerns with the Company's choice to reject results from the Strategist model by citing the Aurora model, in this case, both based on the interpretation of results and fundamental problems within the Aurora analysis itself.

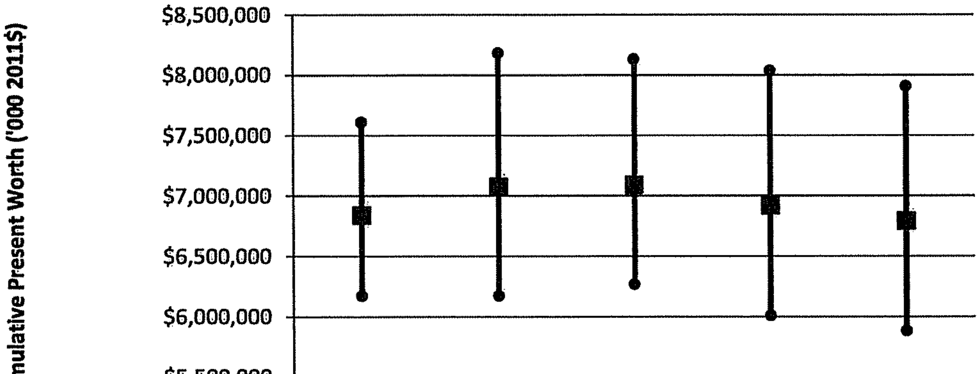
Q Where does the Company reject Strategist results on the basis of the Aurora model?

A In Mr. Weaver's testimony (p 47 at 15- p 48 at 2), he specifically states that "although the 'discrete' risk modeling results – shown on Exhibit SCW-4 – from the Strategist-based modeling point to this Option #4B as being a near 'wash' with a Big Sandy 2 DFGD retrofit solution, this additional Monte Carlo risk modeling indicates KPCo's customers would be potentially exposed to *significantly* greater cost-of-service/revenue requirement uncertainty in the future under that 'market' alternative." (emphasis in original)

If we take the Company's interpretation of the Aurora outcomes at face value, these model results would suggest that all other alternatives, market-based or no, should probably be rejected on the basis of its attendant risk (which is essentially identical for Options 2, 3, and 4b).

What Mr. Weaver does not state here is that while the Aurora model appears to show an apparent downside risk to natural gas purchases (market or steel-in-the-ground), the same results also show a large upside benefit as well– i.e. the model results would indicate that consumers have nearly as high a probability of coming out far better than far worse with a market replacement.

Indeed, simply drawing from the Company's data with no alterations to either Strategist or Aurora, we can re-cast the Strategist and Aurora results as the Company claims it intended. In **Figure 5** below (**Exhibit JIF-9**), I show the "Base" scenario outcomes from the Strategist model,[45] plus error bars representing the Aurora uncertainty ranges at the 5th and 95th percentile.[46]



	'BASE' Option #1	Option #2	Option #3	Option #4A	Option #4B
95th % Aurora Risk	7,609,980	8,182,166	8,130,133	8,034,108	7,907,927
Strategist ("Base") Outcome	6,838,879	7,075,297	7,091,182	6,917,767	6,791,587
5th % Aurora Risk	6,171,648	6,172,690	6,268,489	6,008,162	5,881,981

Figure 5. Company results (unaltered) of cumulative present worth (CPW) of Options #1-#4B. Center points represent Strategist outcome in "Base" commodity scenario. Upper and lower bounds represent range of 95th and 5th percentile outcome from Aurora results. Assumes 4A has same risk profile as 4B.

What becomes immediately apparent in this graphic is that the error bounds (as used by the Company, and under Aurora assumptions used by the Company) swamp the differences between the scenarios as shown in Strategist models.

Q Do you have a concern with the Aurora model as used here, specifically?

A Yes, I do. I have five fundamental objections to Aurora model as presented in this hearing.

[45] Directly from Exhibit SCW-4A

[46] Calculated from Sierra DR 2-35c-d (data behind graphs in SCW-5)

First, the results of the Aurora model differ dramatically from the results generated out of the Strategist model, and the differences cannot be reasonably attributed to differences identified by the Company in discovery responses.

Second, the Aurora model as utilized and presented in both testimony and discovery responses is opaque and generally non-auditable.

Third, the correlations between variables that the Company claims were used in the Monte Carlo analysis are derived from inadequate data, contain fundamental errors, are not represented in the model, and have inappropriately introduced bias into the analysis.

Fourth, it is unclear how these correlations were actually used in the Monte Carlo analysis. Conceptually, these correlations should play an important role in how different variables "move" in relation to one another. However, in the files supplied, we are unable to find any mechanism that successfully replicates the stated correlations.

Fifth, the Company has not presented the Aurora model used thusly to this Commission in previous proceedings for independent evaluation, and has supplied inadequate information to allow this Commission to evaluate if the model has been utilized correctly in this proceeding.

Overall, it is my contention that the Aurora model is so poorly supported, so erroneous, and so fundamentally disparate from the more transparent Strategist model runs that <u>the Aurora model runs used for this proceeding should be disregarded in their entirety</u>.

I will discuss each of the above concerns individually.

10. AURORA CONCERNS: CONTRASTING AURORA AND STRATEGIST OUTCOMES

Q You have stated as your first objection that the results of the Aurora model differ from the Strategist model. Why is this important?

A As I state above, even though the Company discusses Aurora only in the context of revenue requirement at risk (RRaR), Exhibit SCW-5 shows the absolute outcomes of the Aurora model on a relative scale, leading to the very likely interpretation that the Aurora model independently estimates the complete CPW of each scenario in a comparable fashion to Strategist. This misinterpretation is compounded by a label in Exhibit SCW-5 that marks the values as CPW of " 'G' costs", or the total incremental revenue requirement of the scenario as used elsewhere in Mr. Weaver's testimony (i.e. p18 at 6 and p35 at 6).

Q What is so different about the results of the Strategist and Aurora models?

A Simply stated, the Aurora model estimates that the (median) net benefit of retrofitting the Big Sandy 2 is anywhere from $350 to $609 million *more* than the Strategist model's output – or anywhere from double the benefit to well over ten times the benefit; results that simply don't hold water – particularly as they are examined more closely.

The vast differences between the Aurora and Strategist runs are illustrated in the **Table 7 (Exhibit JIF-10A)** below. The differences, in millions 2011$ CPW are directly extracted from exhibits of Mr. Weaver.

Table 7. Differences in relative net benefit of retrofit versus other alternatives.

Net benefit of Big Sandy retrofit versus:	**Option 2:** Replace with NGCC	**Option 3:** Repowered BS1	**Option 4a:** Market until 2020 NGCC	**Option 4b:** Market until 2025 NGCC
Strategist Ex. SCW-4	$236 M	$252 M	$79 M	$(-47) M
Aurora Ex. SCW-5 (p1)	$586 M	$527 M	Not modeled	$562 M
Relative advantage conferred by Aurora	$350 M	$275	-	$609 M
% Difference	248%	209%	-	1,195%

For each of four options (1, 2, 3, and 4b), the Aurora model is run 100 times and subsequently returns 100 different results. However, because the baseline (median, in this case) input variables that go into the Aurora model are identical to the commodity prices in the Strategist "Base" case, we would reasonably expect that the median output from the Aurora model would replicate closely, if not exactly, the Strategist output. This is clearly not the case.

Q Does the Company have an explanation as to why these results are so different?

Mr. Weaver appears to concur that the differences are confounding. In Sierra DR 1-5f, he states that "the results vary … because the models are unique and thus have different internal dispatching logic that can result in absolute answers that are different" but that "given enough iterations of Aurora, one might reasonably expect that the median values of the Aurora approximately equal the Strategist solution, save for the inherent (and proprietary) differences in the model's internal logic."

Mr. Weaver poses two hypotheses in his explanation –

- **first**, that it is feasible that the Company did not run Aurora enough times to converge on a robust solution, and
- **second**, that the models would have resulted in disparate results because of logical differences in dispatch.

The first hypothesis can be rejected quickly. If the Company were truly uncomfortable with its modeling for a nearly one billion dollar retrofit project, I expect that they would have run the model through more iterations. However, for showing the differences between the model runs, the Company reports median (middle) values, which, from a statistical standpoint are fairly robust, so I do not expect that additional model runs would have resulted in substantively different results.[47]

[47] One way of showing the robustness of the median here is by examining how tightly bound the value is within the range of potential answers. The median represents the 50th percentile answer – moving to the 40th percentile answer instead, the difference between it and the median is always less than 3% of the total span of answers. Even if the Company ran another 20 runs and each one came out lower than the 40th percentile answer, the new median would only shift to the 40th percentile – or by 3%.

The second hypothesis implies that dispatch logic alone is sufficient to explain these dramatic differences. I agree that dispatch dynamics are probably one element that is significantly different between these two models – but this alone does not explain the difference. In fact, comparing these two models (or at least the information supplied by the Company and used for their cost comparisons) suggests apples and oranges comparisons with respect to just about every material factor – and overwhelmingly large differences in how the models treat market purchases and sales, and capital expenses.

Q Why do you think that the models do not simply differ in dispatch dynamics, and why would you want to compare more than just CPW?

A While differences in the CPW are useful for final decision-making, how costs are assumed to expend over time is illustrative and critical for understanding the basis of the decision. In Sierra DR 2-35a-b, the Company finally supplied the detailed outputs from the Aurora results (the "Aurora workbooks").[48] These spreadsheets are comprised of matrices dimensioned by year and Aurora iterations. We can trace the final value used by the Company in Ex. SCW-5 back to component parts, and in turn, trace those component parts over time.

The Company also supplied what I will call the "Strategist compilation analysis," which appears to take cost component outputs from the Strategist model, as well as other data sources, and creates a stream of expected costs over time, the CPW of which were used for Ex. SCW-4. The worksheets for the Strategist Compilation Analysis were supplied in Staff DR 1-48, and formula-enabled versions with key underlying worksheets were supplied as a supplemental to Sierra DR 1-69 on February 22, 2012.

[48] Workbooks are IRP_XMP_DGTool_KPCO_BS_Retirement.xls, IRP_XMP_DGTool_KPCO_BS1_Repower.xls, IRP_XMP_DGTool_KPCO_BS2_Retrofit.xls, and IRP_XMP_DGTool_KPCO_NGCC_Replacement.xls

I compared the cost categories supplied in the Company's Aurora workbooks against the cost categories in the Company's Strategist compilation model.[49] The cost categories summed in each model are listed in the **Table 8 (Exhibit JIF-10B)** below.

Table 8. Cost Category names in Strategist and Aurora

Cost Categories	Strategist Compilation Analysis Name	Aurora Spreadsheets Name
Fuel Costs	Fuel Cost	Fuel Costs
Contract Purchases & Sales	Contract Revenue	Contract Revenue
Market Purchases & Sales	Market Revenue / (Cost)	Net Cost of Imports
Capital Expenditures	Carrying Charges	*Not in Aurora Analysis*
Variable O&M	Incremental O&M [and Base O&M]	Variable O&M
Fixed O&M		Fixed O&M
Emissions Allowances	Market Value of Allowances Consumed	Emissions Cost
Capacity Cost	Value of ICAP	ICAP

With one exception, that of capital expenditures, the category titles can generally be matched between the two analyses. As far as I am aware, capital expenditures, including the costs of the FGD or any replacement capacity, are completely absent from these analytical results. Unless these costs have been inexplicably pushed into the "Net Cost of Imports," it is entirely unclear if the Aurora analysis takes capital expenditures into account at all in the final results.

The similarities generally end with the name of the cost category. **Figure 6 (Exhibit JIF-11A)** below, shows the CPW (in '000 of 2011$) of Options 1, 2, and 4b, broken down by cost category for both the Strategist (base case) and

[49] The output of Strategist runs are apparently put through a compilation model, the bulk majority of which appears to have been delivered as a supplemental to Sierra DR 1-69 in response to a Motion to Compel. Formula-disabled versions of these worksheets were delivered to Staff in response to Staff DR 1-48.

Aurora models (median solution). As will be detailed below, to the extent that these two models appear to result in *total* CPW that are even within range of each other may be no more than coincidence; the degree to which any differences between options can be examined at face value is suspect.

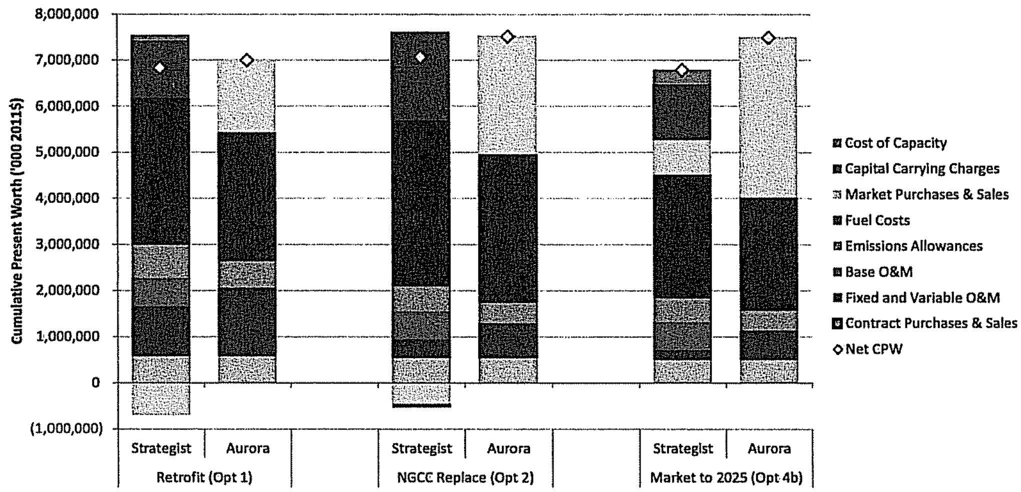


Figure 6. Comparison of CPW cost components between Strategist and Aurora models. Each pair of columns represents the total CPW of an Option as portrayed by either Strategist or Aurora. Working from the bottom up:

- <u>Contract Revenues</u> (or in this case, costs in each model) are fixed in the Aurora model based on Strategist, so there is no discrepancy between these values.
- <u>O&M</u> values are moderately comparable, if Base O&M costs[50] are included, yet are still consistently 14-35% higher in the Strategist analysis across all options.
- The cost of <u>pollution allowances</u> are consistently 20-25% higher in the Strategist runs, representing both higher costs for near-term allowances (SO_2 and NOx) and long-term allowances (CO_2).

[50] Base O&M costs appear to be O&M associated with "another case with only those additions already present in 2011" (*see* response to Staff DR 2-2f) and are subtracted from all Options in the Strategist runs. The stream of Base O&M costs can be found in the supplemental response to Sierra DR 1-69 in any spreadsheet on the "O&M" tab W34:W63.

- Total fuel costs, the variable that I would expect to be most influenced by "different internal dispatching logic" is consistently higher by 9-14% in the Strategist model.
- Capital carrying charges do not appear to be represented in the Aurora model at all, meaning that important differences between the avoidable costs of construction (i.e. the FGD or replacement NGCC) and the uncertainty of those costs are not considered at all in this analysis.
- Market purchases are completely different between these two models, with Strategist predicting net market sales in Options 1-3, and Aurora predicting massive net market purchases in all cases. Figure 7 below (**Exhibit JIF-11B**) illustrates the massive discrepancies between market purchases in the Aurora and Strategist model, amounting to, for example a difference of over three billion dollars in Option 2 (NGCC replacement in 2015).

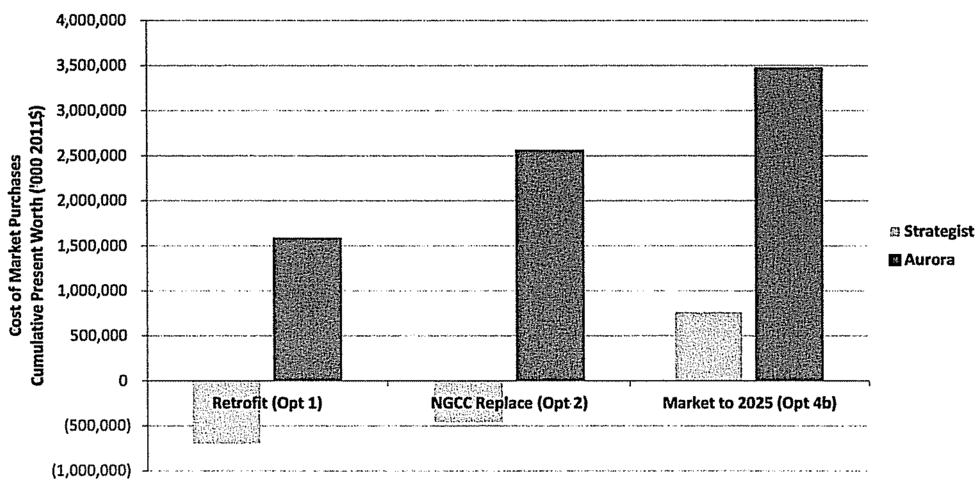


Figure 7. Contrasting market purchases between the Aurora and Strategist models in three scenarios.

- Capacity purchases, while a smaller component of the overall CPW, appear to have a similar, but inverted, relationship between the two models. Strategist often predicts net capacity purchases and Aurora predicting net capacity sales.

It is important to note that the Company is evaluating which option to pursue on the basis of the *difference* between net CPW costs in each model. These CPW differences are on the order of tens of millions to a maximum of about $500 million in the Strategist model (*see* Ex. SCW-4) – yet the differences between <u>components of the Strategist and Aurora models differ by up to three billion dollars CPW, in evaluating the same Option.</u>

I am unable to find a reasonable mechanism to rectify these disparate results.

Q Why are capital carrying charges not included in the Aurora analysis?

A It is not clear to me why capital charges are not included. A stochastic analysis like Aurora could be well suited to examine uncertainty in build costs as part of the total financial risk package.

The lack of capital carrying charges in this model is inconsistent with Mr. Weaver's Exhibit SCW-1 (p10) that states "the input variables…considered by Aurora$^{XMP®}$ within this analysis were [amongst other variables] construction costs (annual carrying costs) ($/kW-year)." This lack is also in stark contrast to the response of Mr. Weaver to Sierra DR 2-6a that states that amongst "the variables [that were] allowed to vary stochastically in the Monte Carlo analysis… [are] Construction Costs [as] implemented in the FOM variable." The fixed O&M (FOM) variable in Aurora appears to only represent FOM costs as implemented in Strategist – not the major capital expenditures (i.e. the FGD or new/repowered NGCC units). In addition, this variable is held almost perfectly constant. In the retrofit Aurora run (Option 1), the CPW of FOM costs displays less than a 0.1% variance – effectively held completely constant. Indeed, the only variance in the FOM variable occurs after 2025, possibly representing some level of uncertainty in the FOM of the small additional NGCC added in out-years.

11. AURORA CONCERNS: LACK OF TRANSPARENCY

Q You have stated as your second objection that the Aurora model as used in this proceeding is generally opaque and non-auditable. Please support that contention.

A Sierra Club repeatedly requested the input and output files from the Aurora model[51] to be able to better understand how the Company was using this platform, and if the inputs and process were consistent with other Company assumptions. From the first request (Sierra DR 1-69), we received only a list of 100 CPW values – with no component costs, no formulae, and no basis. From the second request (Sierra DR 2-35a-b) and a separate Motion to Compel, we received a series of worksheets that break down the 100 CPW values into their component costs over time – but these worksheets arrived without formulae and the supporting workbooks are simply pasted values from another source. It appears that formulae were purposefully disabled in this worksheet.

I have been able to reconstruct some components of the Aurora outcomes, but have no mechanism to be able to rectify those outcomes with input data, or even sufficiently trace which input data actually went into the Aurora analysis.

I contend that the Commission and interveners are unable to verify that the Company has provided a robust analysis in the Aurora model, and therefore cannot audit, much less rely upon the results of the Aurora analysis. As far as I am able to tell, the Company could have used arbitrary, or even biased, input data for this model and it would be impossible to know based on the information provided by the Company in this proceeding.

Q Are there examples of where the information provided by the Company in the Aurora analysis appears to be internally inconsistent?

A Yes, there are. One of the key components of this analysis the "risk factors," or ranges of uncertainty that six specific variables are allowed to take (*see* Exhibit

[51] Sierra DR 1-69 "provide all assumptions and workbooks, in electronic format and with all calculations operational and formulate intact, used to prepare SCW-1 through SCW-4, including output files from the Aurora model."

SCW-1, p10 at second paragraph under section A). In Sierra DR 2-34b, interveners requested "the distribution assumed for each of the six key risk factors considered." In response, the Company delivered a spreadsheet with the "risk factors" of 15 variables:

- one of which appears to represent the variance of demand,
- eight of which appear to represent coal distributions,
- two of which appear to represent natural gas price distributions
- one of which <u>may</u> represent market price distributions, and
- three of which are completely unlabeled ("Generic") and do not appear to correspond to any known variable – either CO_2 prices or construction cost risks.

We are unable to determine which of these variables, if any, are actually used in the Aurora model. As noted previously, the Company also supplied opaque "Aurora workbooks" that, if reconstructed, appear to be elements of the output from the Aurora model. Three worksheets in these workbooks correspond to natural gas prices (2025-2040), coal prices, and CO_2 prices. Theoretically, if the distributions provided in Sierra DR 2-34b have any relationship to the input represented in these workbooks, the pattern (if not the absolute value) of variable distributions should correspond well between these two data sources. As presented, the natural gas prices correspond perfectly, but the coal and CO_2 prices do not correspond.[52] Again, without a moderately linear analytical pathway, it is impossible to know what data was used by the Company in the Aurora analysis, and what the outputs represent.

[52] We can test the correspondence of the reported inputs in the distributions against the reported inputs in the Aurora workbooks by simply looking at how well a trendline fits the data. For the coal prices against the coal price distributions, the r^2 value is 0.46, meaning that 46% of the actual variance in coal prices can be described by the "coal price distributions". In the CO_2 tab, the r^2 value is effectively zero (0.01) meaning that the reported inputs have no relationship whatsoever to the Aurora reported model data.

12. Aurora Concerns: Faulty Correlations

Q What is the purpose of the correlations as used in this proceeding?

A There are at least two ways of running a stochastic model - or a model that can handle a range of uncertainty. One way is to assume that all of the variables that are uncertain vary randomly, with no relation to one another; in that circumstance, one might have no information about how variables are related, or one might know for certain that they do not influence each other.

Another way of dealing with uncertain variables is to tie them together with correlations. In that case, one might know or have ample reason to believe that as one variable changes, another will change with it. For example, one might know that every time it gets hot, electricity consumption increases – these two variables move together. If one was going to run a model in which both future temperature and electricity consumption were uncertain, it might be beneficial to tie these two variables together such that they tend to follow one another. In this same way, the Company has introduced correlations between most of its driving variables in the Aurora analysis.

Q What is the effect of using a high correlation between two variables?

A Since variables that are highly correlated will tend to move together, variables with a high correlation may have an amplifying affect if those variables both represent a driver in the same direction. Take, for example, gas prices and power prices – if either of these variables increases, then the cost of a portfolio that includes both gas and market purchases will increase. If the variables are tied together via a correlation, then any time either one increases, the other will increase as well – and the total portfolio cost will increase. The correlation here would have an amplifying effect.

If these variables were not correlated, then the total price would be far less sensitive to fluctuations in the price of gas or market purchases. If these two variables were inversely correlated (i.e. a negative number approaching negative 1) then they'd have a dampening effect on each other – as the market price of power increases, the cost of gas decreases – and so total portfolio costs remain more stable.

Q How do you think the correlations used by the Company influenced the model outcome?

This is a difficult question because it is not apparent that the correlations presented by the Company in Exhibit SCW-1, Table 1-4 actually represent the values used in the Aurora model. I present the correlation values that it appears the Company used in the Aurora model later, in

Table 9 of my testimony.

Given the correlations, I believe were actually used in the model, I think the correlations deeply influenced the outcome, and may have unduly biased the results

As noted previously, the Company uses Aurora to look at the uncertainty bounds on total portfolio prices (via Revenue Requirement at Risk, or RRaR) using a model with explicit correlations, some of which are fairly high. In particular, it appears, based on Sierra DR 2-34b, that the Company imposed very high correlations between demand, market prices, and gas prices – but a very low correlation between demand and coal prices.

For a portfolio that is rich in gas or market purchases – such as Options 2, 3, or 4a/b – random <u>upward</u> shifts in demand (the "driving" variable) will tend to amplify not only the amount of power that is required, but also increase the price of that power if it is purchased from the market or a gas generator. This makes for a very expensive portfolio. Inversely, random <u>downward</u> shifts in demand will tend to create a very low cost for a gas or market-rich portfolio.

For a portfolio that is coal-heavy, such as Option 1, changes in demand shift market prices,[53] but do not impact coal prices at all, and thus the Option is very insensitive to changes in demand and market prices.

One would expect, looking at these correlations, that a gas or market-rich portfolio will tend to come out of the model with a very wide range of portfolio costs, while a coal-heavy portfolio will come out looking fairly stable. And in fact, that is exactly what we see in the final outcomes in Ex. SCW-5.

It is not at all surprising, based on these correlations, that the Company's examination of upside risk (RRaR at the 95th percentile) proves unfavorable for Options 2, 3, 4a or 4b. It is my belief that the RaRR found by the Company is

[53] Increased market prices are favorable for the net off-system sales of Option 1.

largely a product of the correlations imposed by the Company, and I do not believe that those correlations are well founded, as I will describe below.

Q You have stated as your third objection a number of directed concerns with the correlations used in the Company's Aurora model. Can you briefly outline those concerns?

A I have reviewed the data that the Company used to derive the correlations in Sierra DR 1-61, and I am not satisfied that the correlations are either real or in any way accurate. The following concerns are fairly technical in their nature, but require documentation, for it is my understanding that using a different set of correlations would probably have resulted in very different Aurora results. Briefly:

- The correlations presented in Exhibit SCW-1, Table 1-4 do not represent the correlations actually used by the Aurora model.
- The Company has confounded temporal change, or change over time, with uncertainty;
- The Company has mixed correlations from historical and future data over very different time spans representing very different processes;
- The Company erroneously used a measure of amount instead of price when reviewing the historic cost of coal versus other factors;
- The data used to derive correlations in the future are non-robust, changing sign with the simple exclusion of incorrectly-used data;
- By introducing incorrect and large value correlations, the Company has inappropriately introduced bias into their analysis, a bias which favors Option 1 (the retrofit).

Q Why do you think that the correlations presented in SCW-1 Table 1-4 are not the same as actually used in the Aurora model?

A In Sierra DR 2-34b, Sierra Club requested the "distribution assumed for each of the six key risk factors considered in the Aurora model." In response, the Company provided a very long table of values that appear to contain "risk factors," which I interpret to be the expected variance on individual factors. I examined the correlation of these factors against each other[54] and arrived at a very different set of correlations than provided by Mr. Weaver in Table 1-4.

[54] Assumes that Demand represented Demand, KPCo_External_Supply represented the market price of electricity, AEP_FUEl_BIGS2 represented the variance on coal price at Big Sandy 2, AEP_FUEL_CC_KP represented the gas price variance, and that Distribution 28 represented CO_2 price variance (although the final correlation is insensitive to if Distribution 27, 28 or 29 are utilized).

Table 9 below (**Exhibit JIF-12A**) shows the correlations presented by Mr. Weaver in Table 1-4, the correlations I've derived from the data supplied by the Company in Sierra DR 2-34b, and the difference between the two sets.

Table 9. Comparison of correlations presented in testimony and derived from discovery.

Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	(0.23)	0.88	seasonal
Coal		1.00	0.69	0.19	0.74
Carbon			1.00	(0.14)	0.50
Power				1.00	0.75
Demand					1.00

Correlations derived from Sierra DR 2-34b

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	*0.45	0.88	0.66
Coal		1.00	0.05	0.10	0.08
Carbon			1.00	0.53	0.68
Power				1.00	0.76
Demand					1.00

*Assumes CO2 is Generic Distribution 28

Europe	US	Hypothesized

Difference

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price		0.00	(0.68)	0.00	
Coal Price			0.63	0.09	0.66
Carbon Price				(0.67)	(0.18)
Power Price					(0.01)
Demand					

Q Did the Company actually use the correlations reported in Sierra DR 2-34b or SCW-1 in the Aurora Model?

A It does not appear that they did. In response to Sierra DR 2-35a-b, the Company provided selected outputs from the Aurora model, including the CO_2, natural gas, and coal prices apparently used in each run and each year. Working from the actual values, I derived the variance of each of these commodities as used in the Model and compared the variance against the values reported in Sierra DR 2-34b.

The variance of natural gas prices matched nearly perfectly, but both coal and CO_2 were almost completely unrelated.[55]

After having tested numerous combinations and permutations of data provided by the Company, I can be fairly certain that I am reviewing the data correctly. Thus, I surmise that either the Company provided incorrect data in response to one or more requests, used inconsistent data in the model, or has misstated how (or if) the model uses the correlations provided by Mr. Weaver.

Q What do you mean that the "Company has confounded temporal change with uncertainty"?

A Simply stated, the purpose of the correlations is to examine how variables "move" relative to each other –

- high positive correlations mean that variables will move closer to in synch,
- high *negative* correlations mean that variables will move in synch in opposite directions, and
- low magnitude correlations mean that variables will move independently.

The Company has derived these correlations by looking at historic time series for some types of known variables (such as natural gas price and "demand" using U.S. generation as a proxy), and future time series for others derived from a UK futures market (ICE). The Company found correlations (or a lack thereof) between incremental changes in price from year to year. However, many of the variables that were examined (including the futures price for UK coal, UK gas, and EU carbon) are derived from nominal dollars, which introduces a positive correlation bias. Indeed, any long-term trends will introduce a positive bias into this analysis.[56]

[55] It should be noted that the cross-correlation of these three variables also did not match either the correlation values given in Table 1-4 in SCW-1 or the correlations derived from Sierra DR 2-35a-b.

[56] If the Company were examining year-to-year uncertainty, which they are not, it could be argued that examining interannual changes without removing trends is appropriate; as used in Aurora here, the Company attempts to simulate uncertainty relative to an "average" behavior in each year independently, and thus introduces bias by using trended data.

Q **Why is using correlations from future and historic data problematic?**

A Within reason it should not be a problem to use recent history and reasonably expected futures data as required. However, in this analysis, the Company mixes correlations from a sparsely populated (data-wise) European futures market to 2014 for CO_2, coal and natural gas relationships[57] with correlations from U.S. data for coal and thermal generation stretching back five decades. There is little reason to think that these data represent anywhere near a similar process as each other – it is unlikely that 1950s vintage relationships between coal prices and demand represent processes that are still happening today.

Q **What data did the Company use to derive the relationship between coal prices and demand?**

A In the single use of actual U.S. data, the Company erroneously used coal <u>tonnage</u> instead of coal <u>prices</u> to create a correlation between demand and fuel price. Correcting this error changes the relationship from a very correlated 0.74 to a low value of 0.08.

Q **What do you mean that the data used for the correlations are non-robust?**

A Putting aside the question of if the correlations presented by Mr. Weaver were actually used in the Aurora model, the data that the Company has used can swing dramatically just from small changes in the way that they are used. Of the nine correlation values that Mr. Weaver presents in Exhibit SCW-1, Table 1-4, two are complete guesses (yet high values, nonetheless) and six are derived from very sparse data.

The Company wanted to provide some data to show a relationship between commodity prices (particularly gas and coal) and CO_2 prices. Because there is not yet an active national market for CO_2 in the US, the Company turned to Europe to represent an active carbon market, and used UK commodity prices to match. Examining changes in fuel, CO_2, and market prices, the Company used reviewed

[57] These factors are feasibly the most important in this set.

exactly nine quarters of forward prices on the ICE market – between June 2011 and June 2013.[58] The futures report shifted to annual timesteps after June 2013, so the Company then added a nine-month step and an annual step, finishing with 11 data points in December 2014. First, changes over quarters may be quite different from changes over annual timesteps (i.e. seasonal gas swings vs. annual increments); second, the eleven data points are very scattered and very non-robust.

Simply removing the 9-month span and the annual span from the series makes the correlation between gas price and CO_2 drop from -0.23 to -0.52. Randomly removing any two datapoints from this series results in answers ranging from a correlation of +0.34 to -0.54.

Finally, the Company chose to use very sparse European data to determine a relationship between coal and gas, as well as between electricity market prices and those fuels. Without suggesting that adopting historic domestic data is any improvement or should be used instead, simply examining trends of U.S. retail rates and U.S. natural gas prices against U.S. coal and U.S. demand results in, again, a very different correlation.

In

[58] The Company used vintage data, hence the forward price start at June 2011.

Table 10, below (**Exhibit JIF-12B**), I've examined domestic gas, demand, and retail prices, removed the 9-month and 1-year span in the European data for carbon correlations and presented an alternate matrix to Ex. SCW-1, Table 1-4. This table is provided for illustrative contrasting purposes only. I do not believe that the statistics used by the Company (or presented here) are the correct mechanism to evaluate uncertainty correlations. I think that, in absence of robust and supportable information, I would suggest that no correlations be used in this particular uncertainty analysis.

Table 10. Comparison of correlations presented in testimony and derived from domestic data.

Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	(0.23)	0.88	seasonal
Coal	0.00	1.00	0.69	0.19	0.74
Carbon	0.00	0.00	1.00	(0.14)	0.50
Power	0.00	0.00	0.00	1.00	0.75
Demand	0.00	0.00	0.00	0.00	1.00

Synapse (for contrast only)

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price	1.00	0.11	(0.43)	0.41	(0.15)
Coal Price		1.00	0.67	0.32	0.11
Carbon Price			1.00	(0.43)	0.00
Power Price				1.00	(0.51)
Demand					1.00

Europe	US	Hypothesized

Difference (Company minus Synapse)

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price		-0.03	0.20	0.46	0.81
Coal Price			0.01	(0.14)	0.63
Carbon Price				0.30	0.50
Power Price					1.26
Demand					

Q Mr. Weaver supports the strongly positive correlation between demand and market price in Sierra DR 2-32b. Do you agree with his assessment?

A No, not at all. Sierra Club questioned if "the positive correlation of 0.75 means that the Company assumes that retail load will increase as wholesale power prices increase…" and Mr. Weaver responded that "in the shorter run, as demand increases … the cost of supplying that power increases as progressively more expensive units must be dispatched."

The general principles of economic dispatch over short time periods are not in dispute. However, this is not the question poised in the Aurora model or answered by these correlations. The uncertainty in the Aurora model appears to represent annual departures from a mean, not movement along a dispatch curve – that type of movement is not uncertain at all, and not only extremely well characterized by this dispatch model but completely endogenous. The model is already very well equipped to increase market prices in response to short term demand increases; this correlation asks for a representation of how demand shifts in response to price changes.

Indeed, if we look at <u>annual</u> changes in electricity sales (not de-trended) and average electricity prices[59] from the same dataset provided as the response to Sierra DR 2-32b[60] we see a fairly consistent negative correlation of about -0.36. This same correlation is repeated for Kentucky and Ohio consumers (-0.37) and (-0.33).

13. <u>AURORA CONCERNS: USE OF AURORA TO SUPPORT THIS FILING</u>

Q You have finally noted that the Company has not presented the Aurora model used in this manner to the Commission previously. Why is that important in this case?

A It is important for the Commission and independent evaluators, such as the interveners in this and other proceedings, to be able to examine how the Company uses modeling to support their conclusions – particularly if the basis of a decision rests so heavily on a modeled outcome, as in this CPCN. The Aurora model, while apparently only a small part of the overall modeling performed by the Company, is used by the Company to reject two Options – one of which is, by the Company's own estimate, more cost effective than maintaining the Big Sandy 2 unit. It is my belief that if the Company is willing to stand behind the results of this model as the basis for this billion-dollar decision, then the model should be robust, transparent, and well audited.

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[59] As used by Mr. Weaver in his testimony for coal and demand correlation in Ex. SCW-1, Table 1-4

[60] US DOE, Energy Information Administration. Data/Sales (consumption), revenue, prices & customers. Available at http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls

To the best of my knowledge, I understand that this Commission has seen reference to the Aurora model from KPCo as the mechanism by which the Company determines commodity prices[61] and capacity prices,[62] but not as a decision-making tool unto itself.

Q What is your conclusion regarding the Aurora model as used in this proceeding?

A Although I am confounded by the lack of transparency into the model inputs and outputs provided by the Company, from the aspects that I have been able to review, I have found little consistency between the two models (Aurora and Strategist), between the filed testimony of Mr. Weaver and the inputs to the Aurora model, and between the correlations as stated (or used in the model) and correlations derived from a reasonable use of data.

I have found numerous errors and inconsistencies in the Aurora inputs and outputs; and with no ability to trace the use or genesis of the data (or errors), it is nearly impossible to state how influential these errors and inconstancies are in the final outcome. However, based on my observations of the data presented by the Company, it is my assessment that the Aurora model, as presented is more likely erroneous – and potentially biased – then actually useful.

It is my recommendation that the Commission disregard the Aurora analysis in its entirety.

[61] See both AEP East 2009 IRP (p81) and 2010 IRP (p79): "The AEP-SEA long-term power sector suite of commodity forecasts are derived from the Aurora model. Aurora is a fundamental production-costing tool that is driven by inputs into the model, not necessarily past performance. AEP-SEA models the eastern synchronous interconnect and ERCOT using Aurora. Fuel and emission forecasts established by AEP Fuel, Emissions and Logistics, are fed into Aurora."

[62] See KPCo response to Staff DR 2-16 in case 2007-04777.

14. CONCLUSIONS

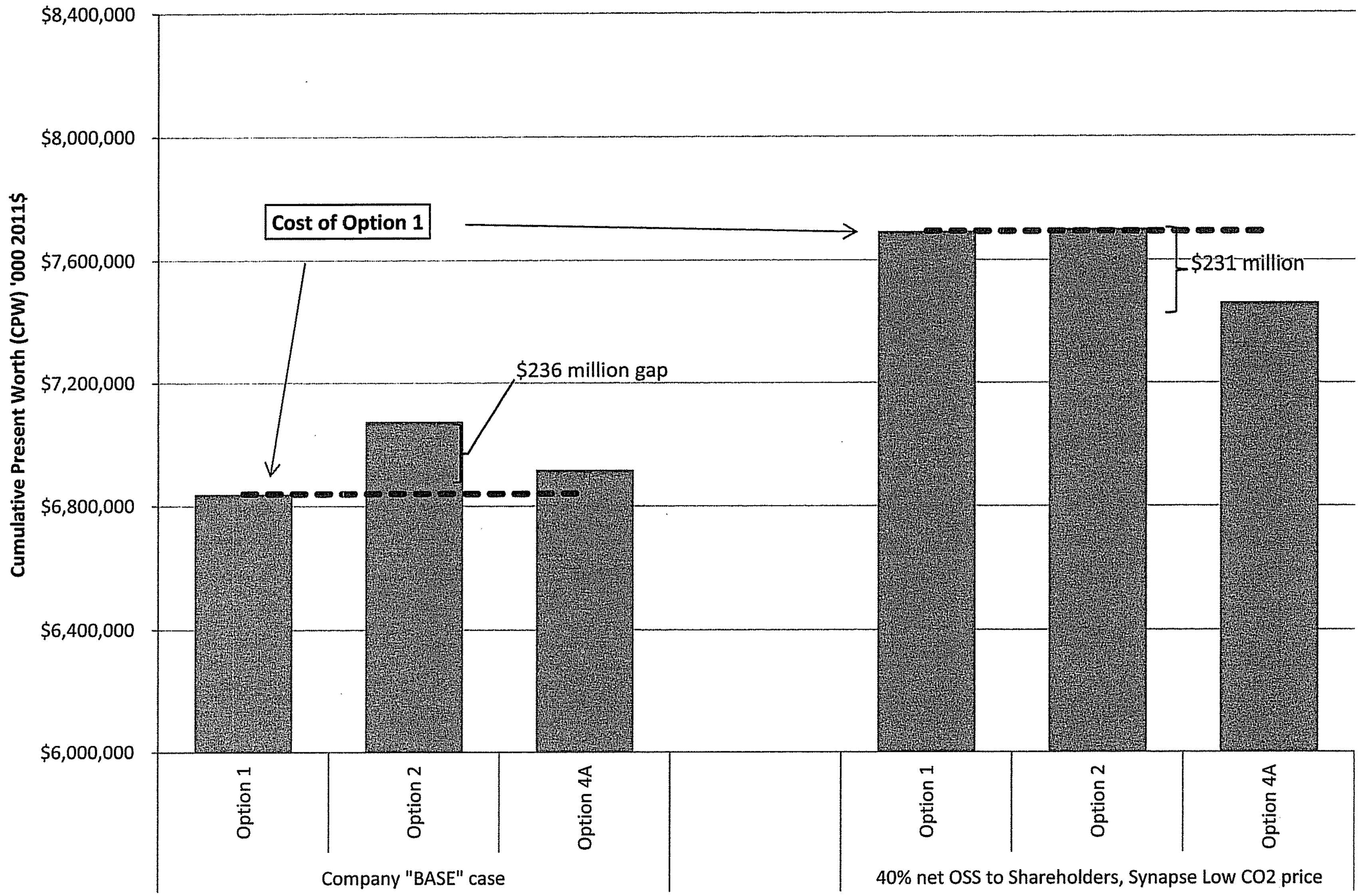
Q What conclusions are you able to draw on the basis of your analysis of the Company's application for CPCN at the Big Sandy 2 unit?

A I conclude that the Company has not provided sufficient evidence that retrofitting the Big Sandy 2 unit with an FGD would be the best option for Kentucky ratepayers. The evidence that the Company has provided is internally inconsistent and ill-founded; when fundamental errors are corrected, the economic benefit found by the Company is removed and reversed.

I find that:

- if the Company expects to continue allocating a sizable portion of revenues from off-system sales to shareholders rather than ratepayers, the relative advantage of the FGD is greatly diminished;
- [redacted]
- the Company's projected CO_2 price forecast is inconsistent with other utilities and the industry at large, and exposes ratepayers to significant regulatory risk. By correcting this value to even a reasonable <u>low</u> bound, the, the relative advantage of the FGD retrofit is eliminated;
- adjusting for off-system sales revenues, capital cost corrections, and a reasonable low bound CO_2 price reveals that the FGD is at least $470 million dollars (in cumulative present worth) more expensive than other options explored by the Company;
- the Company's risk analysis in Strategist are insufficient to elucidate a reasonable range of risks to consumers; and

- the Company's risk analysis in Aurora is internally inconsistent, erroneous, and non-transparent, leading us to question its utility and accuracy.



Cumulative present worth (CPW) of Options 1 (retrofit), 2 (NGCC replace in 2016), and 4A (market purchase to 2020) under Company Base assumptions (left) and Synapse revised assumptions and corrections (right) . See text for details.

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO2 & Adj. Off-System Sales			
	Option #1	**Option #2**	**Option #4A**
Company Assumptions **0**	Retrofit Big Sandy 2 w/ FGD	NGCC Replacement	Market to 2020; NGCC in 2020
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price & Adjusted Off-System Sales			
CPW	7,694	7,702	7,462
Net benefit of retrofit (CPW)		9	(231)

SC EXHIBIT 13

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

And

In the Confidential File Materials at the PSC

EXHIBIT S.C. 14

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, Table 1 and pages 23 to 30. Has the Company considered any other alternatives aside from Options 1-4?

a. If so, please provide detailed descriptions of all other alternatives considered, the level to which they were considered (i.e. discussion only, analysis, modeling, etc…), and any analytical work, such that it exists, that examined the cost efficacy of these other alternatives.

b. If so, please provide any analytical work that supports the non-consideration of those alternatives in the final four options presented here.

c. If not, why not?

d. Has the Company considered the cost effectiveness of replacing Big Sandy with capacity-only replacement, such as combustion turbine without combined cycle capacity?

e. Has the Company considered the cost effectiveness of replacing Big Sandy with a mixture of capacity and energy resources, such as a mix of combustion turbines and combined cycle capacity?

f. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and renewable energy purchases in either the short or long-term (i.e. immediately, up to 5 years as in Option 4A, or up to 10 years as in Option 4B)?

g. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and energy efficiency, demand response, or other demand-side management acquisitions or programs?

h. If the answer to any of (d)-(e) is yes, and as not otherwise provided in answer to (a) or (b), please provide any workpapers showing the scenario considered, the expected costs of the scenario, and any model results from comparing the scenario against other alternatives.

SC EXHIBIT 14

RESPONSE

a. An additional evaluation was performed in January of 2012, after the filing of this case. This assessment focused on the possibility of either acquiring --or entering into a purchase power arrangement-- from affiliate Ohio Power Company for a portion of the Mitchell Unit 1 and/or Unit 2 facilities. These 770 MW and 790 MW, respective coal-fired units are located in Moundsville, West Virginia and have recently been environmentally-controlled with FGDs and SCRs. The timing of this alternative evaluation was based on the recent prospect that Ohio Power Company could become corporately separated and, with that, the generation assets of that company may no longer be regulated and, hence, may be available for sale/transfer.

One of these evaluations calls for the purchase of a 20% portion of the combined Mitchell Units 1 and 2 (or, a total of 312 MW) and is under consideration as a replacement for the proposed retirement of KPCo's Big Sandy Unit 1. This evaluation is intended to be introduced as a proposed component of the 'Section 205' filing with the FERC that AEP is intending to file in early 2012 that would seek to modify the AEP Interconnection (Pool) Agreement.

Additionally, KPCo management also requested that an additional analysis be performed under which Kentucky Power would seek to receive a greater portion from Mitchell Units 1 and 2 (ostensibly, one of the 'full' Mitchell units) that would serve to effectively be substituted for the like-sized Big Sandy 2. This evaluation also assumed that in lieu of retiring Big Sandy Unit 1, it would consider converting that unit to burn solely natural gas (i.e. it would become a "gas-steam" unit).

The attachment to this response is a summary of these indicative Strategist-based evaluations performed in January 2012.

b. As indicated in the response part a of this question, this assessment was performed after this KPCo filing, but does not change the results and recommendation of the filing.

c. N/A

d. The Company has not considered the replacement of Big Sandy 2 with a combustion turbine unit. If Big Sandy Unit 2 were to be retired, KPCo would be replacing a large "baseload" facility that has historically contributed significant amounts of generated energy. As such, if it were to replaced purely with peaking capability --in the form of natural gas combustion turbine (CT) units, or as a unit simply converted to burn natural gas (i.e., a gas-steam unit)--, the Company believes it could be exposed to unacceptable levels of market (energy) purchases and, with that, potential for price volatility for the long-term life of the CTs/gas conversion due to such facilities' would very likely have very low utilization/capacity factors.

e. No. However, this option is essentially captured by, particularly, Options #4A and #4B. See the response Sierra Club 1-51, part a, for an elaboration.

f. No. The Company believes that renewable energy purchases are not substitutable for, particularly, capacity planning purposes. For instance, the PJM RTO recognizes only 13% of the nameplate MW-capacity of wind generating sources for capacity planning purposes. Further, KPCo 2009 request to recover its costs under a proposed wind renewable energy purchase agreement (REPA) was denied by the Commission following opposition by KIUC and the Attorney General.

g. No. While as indicated on Table 1-2 of Exhibit SCW-1, KPCo is projected to achieve 41 MW of demand response (DR) resource by 2016, and at least 60 MW by 2020, such amounts would likely serve to merely adjunct KPCo's resource portfolio, rather than offer a major contribution. As with peaking resources, DR would not contribute much in the way of *energy* contribution. Likewise, that same Table 1-2 of Exhibit SCW-1 also indicates as much as nearly 100 GWh of (annual) energy efficiency contribution being projected for the Company by 2016. However, that level also represents a small (< 2%) percentage of KPCo's overall internal load estimate for that year.

h. N/A

WITNESS: Scott C Weaver

EXHIBIT S.C. 15

AEP OHIO EXHIBIT NO.__________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	)	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY OF

PHILIP J. NELSON

IN SUPPORT OF AEP OHIO'S

MODIFIED ELECTRIC SECURITY PLAN

Filed: March 30, 2012

SC EXHIBIT 15

INDEX TO DIRECT TESTIMONY OF
PHILIP J. NELSON

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
PHILIP J. NELSON
IN SUPPORT OF
AEP OHIO'S MODIFIED ELECTRIC SECURITY PLAN

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip J. Nelson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE INDICATE BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am employed as Managing Director of Regulatory Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Ohio Power Company (AEP Ohio or Company).

BUSINESS EXPERIENCE

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from West Liberty University in 1979 receiving a Bachelor of Science Degree in Business Administration, majoring in accounting. In 1979, I was employed by Wheeling Power Company (WPCo), an affiliate of AEP, in the Managerial Department. At Wheeling Power, I was responsible for rate filings with the Public Service Commission of West Virginia (PSC), for resolving customer complaints made to the PSC, as well as for preparation of the Company's operating budgets and capital forecasts. In 1996 I transferred to the AEP-West Virginia State Office in Charleston, West Virginia as a senior rate analyst. In 1997 I transferred to AEPSC as a senior rate consultant in the Energy Pricing and Regulatory Services Department, with my primary responsibility being the oversight of AEP Ohio's Electric Fuel Component (EFC) filings. In 1999 I transferred to the Financial Planning Section of the Corporate Planning and Budgeting Department where I helped prepare AEP financial forecasts. I held various positions in the Corporate Planning and Budgeting Department until my transfer to Regulatory Services in February, 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF REGULATORY PRICING AND ANALYSIS?

A. My department supports regulatory filings across the AEP system in the areas of cost of service, rate design, cost recovery trackers and tariff administration. It also provides expert witness testimony on AEP's east and west power pools as well as technical advice and support for power settlements and performs financial analysis of changes to AEP's generation fleet. In addition, my department provides support and filing of generation and transmission formula rate contracts.

Q. HAVE YOU EVER SUBMITTED TESTIMONY AS A WITNESS BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified before the Virginia State Corporation Commission and the Public Service Commission of West Virginia on behalf of Appalachian Power Company (APCo), before the Public Service Commission of West Virginia on behalf of WPCo, before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company (I&M) and before the Public Utilities Commission of Ohio (Commission) on behalf of Columbus Southern Power Company (CSP) and Ohio Power Company (AEP Ohio).

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I provide an overview of the Company's corporate separation plan being filed in a separate application before this Commission. I present information responsive to the Commission's directive in its March 7, 2012 in Case 10-2376-EL-UNC,et al. to address the plan for AEP Ohio's generating assets, including retirements and divestitures. I describe the Standard Service Offer (SSO) contract between AEP Ohio and AEP Generation Resources Inc. (Genco). I discuss the current Fuel Adjustment Clause (FAC) and the Company's request to continue the FAC for part of the ESP Term. I propose a new Alternative Energy Rider (AER) which will segregate the Renewable Energy Credit (REC) value from Renewable Energy Purchase Agreements (REPAs). I discuss the creation of a new rider to recover costs associated with investment in new generation resources dedicated to retail customers, the Generation Resource Rider (GRR). I sponsor a pool termination provision to recover potential increases in rates if needed as a result of termination of the AEP Interconnection Agreement (AEP Pool).

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring Exhibits PJN-1 through PJN-4:

Exhibit PJN-1 provides a pre and post-corporate separation chart of AEP Ohio, the other AEP East operating companies and AEP Generation Resources Inc. (Genco)

Exhibit PJN-2 provides a list of current AEP Ohio and other AEP East System generating units that are estimated to be retired before June 1, 2015.

Exhibit PJN-3 provides a schedule showing AEP Pool capacity sales and purchases for 2010 and 2011

Exhibit PJN-4 provides additional information on the FAC as required by Ohio Administrative Code (O.A.C.) 4901:1-35-03(C)(9)(a).

CORPORATE SEPARATION PLAN

Q. WOULD YOU PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S CORPORATE SEPARATION PLAN FILED CONCURRENTLY WITH THIS ESP?

A. Yes. The principal purpose of the Corporate Separation filing is to achieve full structural corporate separation of AEP Ohio's generation and marketing businesses, on the one hand, from its transmission and distribution businesses, on the other, consistent with Ohio's corporate separation mandate. Corporate Separation is a fundamental requirement of the Company's plan that will lead to full market-based pricing of generation service for retail customers and will promote retail shopping in Ohio.

Pursuant to Corporate Separation, transmission and distribution-related assets of AEP Ohio will remain in AEP Ohio, which will essentially be a wires-only company upon closing, as more fully described below. AEP Ohio's existing generation units and contractual entitlements, fuel-related assets and contracts, and other assets related to the generation business will be transferred at net book value to Genco. AEP Ohio does not plan to transfer its renewable purchase agreements to Genco. That way, the renewable energy credits associated with those agreements will stay with AEP Ohio, which will remain subject to state-imposed renewable energy obligations. Genco will also assume at closing the liabilities associated with the transferred assets including the retired plants and the liabilities associated with the retired plants.

Immediately after transferring the assets and liabilities to Genco, APCo will obtain the transferred interest in Unit No. 3 of the Amos generating plant and appurtenant interconnection facilities and related assets and liabilities (APCo already owns the remaining interest in Amos Unit No. 3) and an 80% undivided interest in the Mitchell generating plant and appurtenant interconnection facilities and related assets and liabilities (collectively, "Mitchell"), and Kentucky Power Company (KPCo) will obtain the remaining 20% undivided interest in Mitchell.

The long-term indebtedness of AEP Ohio is composed of general obligations that are not secured by the generation assets being transferred to Genco or by any other assets of the company. This unsecured, long-term indebtedness currently consists of two types: senior notes ("Senior Notes") and pollution control revenue bonds ("PCRBs"). In order to manage debt maturities before the closing of Corporate Separation, AEP Ohio may issue new notes to AEP and use the proceeds to repay those debt maturities in the normal course of business. The notes would be subject to approval by the Commission. Company witness Hawkins provides more detail on the financing issues associated with Corporate Separation.

The proposed Corporate Separation plan includes several steps, each of which will occur one after another at closing. The steps of the transaction are detailed in the Corporate Separation filing being made with this Commission. Exhibit PJN-1 is a chart showing AEP Ohio, the other AEP East operating companies and the Genco on a pre and post-corporate separation basis..

The Applicants intend to close the Corporate Separation transaction on January 1, 2014.

<u>SSO CONTRACT BETWEEN AEP OHIO AND THE GENCO</u>

Q. IS THERE A CONTRACT NECESSARY BETWEEN AEP OHIO AND THE GENCO FROM THE DATE OF SEPARATION UNTIL THE SSO LOAD IS SERVED BY THE RESULTS OF AN AUCTION?

A. Yes. In this ESP, the Company is proposing that there will be an auction-based competitive bidding process for the delivery period beginning January 1, 2015 for energy and a separate auction for delivery beginning June 1, 2015 for both energy and capacity. Therefore, between the time of Corporate Separation and the delivery date of the January 1, 2015 SSO energy auction, the Genco will sell wholesale power to AEP Ohio under a full requirements agreement to supply AEP Ohio's non-shopping retail load. The SSO Contract will allow AEP Ohio to serve SSO customers, i.e., those AEP Ohio retail customers that are not being served by a Competitive Retail Electric Service (CRES) provider. From January 1, 2015 through May 31, 2015 the Genco will provide capacity at $255/MW-Day, but will no longer supply the energy for SSO customers under the SSO contract. Beginning June 1, 2015 both energy and capacity will be provided by the SSO auction and therefore the SSO contract between the Genco and AEP Ohio ends on that date.

Q. WHAT WILL THE COMPANY PROPOSE FOR FERC APPROVAL THAT PROVIDES GENCO COMPENSATION FOR MEETING AEP OHIO'S ENERGY AND CAPACITY OBLIGATIONS AFTER CORPORATE SEPARATION AND UNTIL JUNE 1, 2015?

A. In general, AEP Ohio will pass through generation related revenues to the Genco for providing capacity and/or energy for the SSO load. AEP Ohio will pay the Genco the non-fuel generation charges billed to AEP Ohio's SSO customers under applicable retail rate schedules, as well as the Genco's actual fuel costs. AEP Ohio will also reimburse Genco, on a dollar-for-dollar basis, for any transmission, ancillary, and/or other service charges that Genco may be billed by PJM in connection with the SSO Contract.

In addition, revenues that AEP Ohio may receive from PJM in connection with capacity payments made by CRES providers under PJM's Reliability Assurance Agreement ("RAA") would be remitted to the Genco in return for Genco providing capacity to AEP Ohio to fulfill AEP Ohio's Fixed Resource Requirement (FRR) obligations, as well as the obligations of the CRES providers. Also, capacity payments will be made by AEP Ohio to the Genco at $255/MW-Day in connection with the energy only auctions occurring while AEP Ohio is still an FRR entity in PJM.

Also, any revenues related to moving to a competitive generation market in Ohio, such as the Retail Stability Rider, will be remitted to the Genco as compensation for the fulfillment of its obligations.

Q. WHY IS THE AUCTION FROM JANUARY 1, 2015 THROUGH MAY 31, 2015 AN ENERGY ONLY AUCTION AND THE GENCO PROVIDES THE CAPACITY?

A. AEP Ohio and the AEP East system are contractually obligated to remain a FRR entity in PJM until June 1, 2015. In the following section I explain the significance of this contractual obligation.

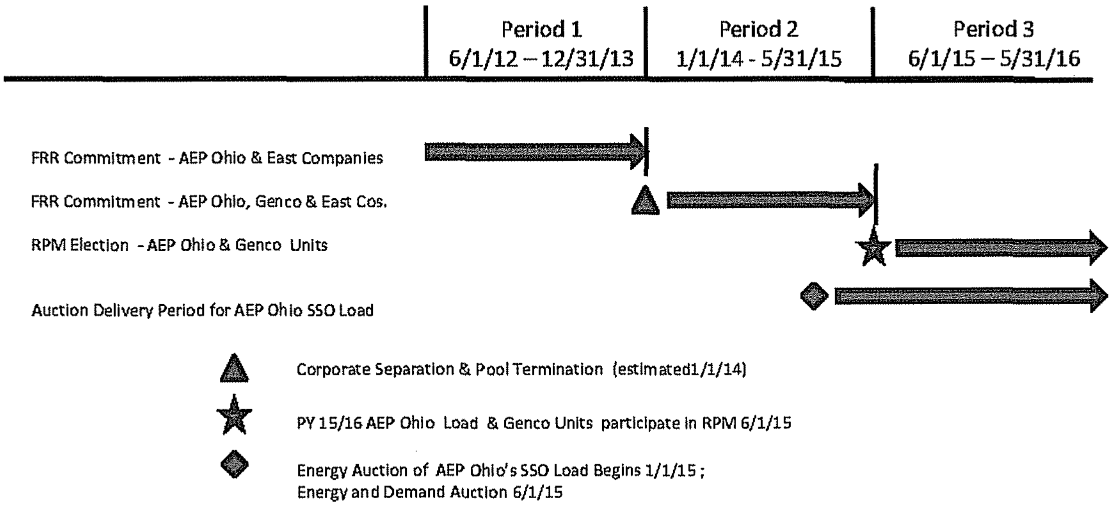
Q. CAN AN AUCTION BASED SSO BE ESTABLISHED FOR AEP OHIO'S NON-SHOPPING LOAD BEFORE CORPORATE SEPARATION IS IMPLEMENTED AND BEFORE THE AEP POOL IS TERMINATED?

A. No, not without the potential to expose AEP Ohio or other AEP Pool members to significant financial harm. First, the AEP Pool was not designed for, nor does it have specific provisions that would address this situation. Therefore, conducting an SSO auction could have substantial impacts on the other members or subject them to recovery risks in their state jurisdictions. Conversely, depending on how an auction is treated for AEP Pool settlements, AEP Ohio might be exposed to significant financial harm. It would also potentially remove AEP Ohio's generation from participating in the SSO auction due to the timing difference between the auction and Corporate Separation.

AEP OHIO CAPACITY PLAN

Q. PLEASE DESCRIBE THE COMPANY'S PLANS FOR FULFILLING ITS LOAD OBLIGATION FROM CAPACITY RESOURCES DURING THE TERM OF THIS ESP INCLUDING PLANS TO DIVEST, RETIRE, AND ADD CAPACITY AND EXPLAIN WHETHER ADEQUATE CAPACITY WILL BE AVAILABLE ON AN ON-GOING BASIS TO OHIO CUSTOMERS?

A. First, as previously discussed, the Company is requesting in a separate filing the authorization to transfer its generating assets to Genco, a separate legal entity, during the course of this ESP. This transfer of the generating assets is necessary to ensure the Company's customers receive auction based SSO pricing in an efficient and expeditious manner. Through the PJM planning year 2014/2015 (PY14/15) AEP Ohio together with the other AEP East operating companies, APCo, I&M, KPCo, Kingsport Power Company and WPCo, have elected as a group (East System) to be under the FRR option in PJM. This requires the East System to provide its own capacity resources to meet its load obligations rather than rely on the PJM RPM market to provide capacity resources. Beginning with PY15/16, AEP Ohio will be separate and distinct from other East System Companies in PJM and has elected to be in the Reliability Pricing Model (RPM) capacity market for its SSO load. Therefore, there are three distinct periods that result in different obligations for the planning of capacity resources. The first period (Period 1) is prior to Corporate Separation and prior to PY15/16. The second period (Period 2) is after Corporate Separation and prior to PY15/16. The third period (Period 3) begins with AEP Ohio's election to to bid its SSO load into the RPM capacity market beginning in PY15/16. The following diagram shows the three periods just discussed.



For periods 1 and 2, the FRR obligation has not changed for the East System. The East companies must continue to provide capacity for all the loads that were submitted to PJM as FRR. The FRR obligation includes the load of AEP Ohio for its SSO customers, as well as the shopping load that is now served by CRES suppliers in AEP Ohio's service territory. After Corporate Separation (Period 2) the FRR generation obligation of AEP Ohio will be assigned to the Genco, which together with the rest of the East System Companies will continue to be required to meet the East System load that has been designated FRR, which includes AEP Ohio's shopping (CRES) and non-shopping (SSO) loads. Beginning with AEP Ohio's election of RPM (Period 3), AEP Ohio is separate from the other East System Companies and the AEP Ohio SSO load is included in PJM's RPM market.

Q. HOW DOES AEP OHIO MEET ITS FRR OBLIGATION?

A. For planning years 12/13, 13/14, and 14/15 certain AEP East generation units and contracts have been committed to PJM as part of the AEP System commitment to meet East System load that has been previously designated FRR. AEP Ohio units and contracts are part of the total pool of generating resources designated by AEPSC on behalf of the East System and there is no requirement to meet the AEP Ohio zone load separate and apart from the other Eastern companies. PJM considers AEP a single zone. The designation of generating resources as FRR is an election made prior to the delivery year. In 2009, resources were committed for PY12/13. In 2010 and 2011 commitments for PY13/14, and PY14/15 were made, respectively. The East System generation resources committed to FRR are provided to PJM three years in advance of the planning year.

Q. WHAT ARE THE PLANNED RETIREMENTS FOR AEP OHIO AND THE AEP EAST SYSTEM GENERATING UNITS AND HOW DO THE RETIREMENTS AFFECT THE AEP EAST SYSTEM'S ABILITY TO MEET ITS FRR OBLIGATION?

A. Exhibit PJN-2, page 1 provides the list of the AEP East System units estimated to retire before June 1, 2015 that was provided to PJM. The ultimate retirement dates for these units will be based on implementation of the new EPA environmental regulations. The East System, based on earlier drafts of the EPA rules, had anticipated and planned for a certain level of retirements during this period. Therefore, at this time the Company believes the East System is in a position to meet its FRR load obligation based on its current capacity resources. Page 2 of Exhibit PJN-2 shows the MW of retirements as a percent of AEP Ohio's fossil generation compared to the retirements of the other East System companies. As can be seen from page 2 of this exhibit the planned retirements are balanced. I show this comparison before and after the Amos and Mitchell unit transfers.

Q. YOU MENTIONED THAT AEP OHIO IS PLANNING TO CORPORATELY SEPARATE AND TRANSFER ITS GENERATING ASSETS TO THE GENCO. IF ASSETS ARE THEN TRANSFERRED FROM THE GENCO TO OTHER AEP AFFILIATES, WILL THIS AFFECT AEP OHIO'S ABILITY TO MEET ITS FRR COMMITMENT?

A. No. As I previously mentioned, AEP Ohio's FRR commitment will be assigned to the Genco upon Corporate Separation, so such "step two" transfers have no impact. Also, as I explained, the FRR commitment has always been done on a system basis, not an individual company basis so the transfer between affiliates will have no impact on the AEP Ohio/East System's ability to meet the FRR load obligation. Furthermore, AEP Ohio has had capacity and energy well in excess of its own internal customer's needs for a number of years and has been selling a significant amount of this surplus generation through the AEP Pool to its affiliates. In 2010 and 2011, AEP Ohio sold about 2,500 megawatts (MWs) and 2,200 MWs respectively to other AEP Pool members. This is shown on Exhibit PJN-3. In order to equitably terminate the AEP Pool, AEP is planning to transfer AEP Ohio's share of Amos 3 and the AEP Ohio Mitchell units to APCo and KPCo which are affiliates and members of the AEP Pool. These units comprise approximately 2,500 MW of capacity.

Q. HOW WILL AEP OHIO MEET ITS RPM CAPACITY LOAD OBLIGATION FOR PY15/16 AND GOING FORWARD AFTER IT BECOMES AN RPM ENTITY IN PJM?

A. It is anticipated that by PY15/16 AEP Ohio will have corporately separated and become primarily a wires company and will be holding auctions to serve any remaining retail SSO load in Period 3. AEP Ohio will bid its SSO load into the PJM RPM market. PJM procures capacity on behalf of LSEs through the RPM auction. CRES providers serving customers in AEP Ohio's territory will procure their own capacity via the PJM auction and no longer be able to rely on AEP Ohio's capacity resources as they have for the planning years preceding PY15/16 when AEP Ohio was an FRR entity.

Q. CAN AEP OHIO STILL PROCURE ITS OWN CAPACITY RESOURCES OUTSIDE THE RPM AUCTION TO SERVE ITS SSO LOAD OBLIGATION?

A. Yes. There is nothing in the PJM RPM requirements that preclude AEP Ohio from owning or purchasing capacity resources. Resources owned would need to be bid into the RPM auction. Likewise, it is my understanding that AEP Ohio as an Electric Distribution Utility (EDU) in Ohio can own or operate a generation facility under provisions of the ESP statute.

Q. IS THE COMPANY PROPOSING TO OWN OR OPERATE GENERATION FACILITIES UNDER 4928.143(C)?

A. Yes, later in my testimony I discuss the GRR, including the Turning Point project which will be requested under this provision of the ESP statute in a separate filing. AEP Ohio considers the request for Turning Point rather unique. The Company has no plans for additional capacity additions under this provision. The Company will rely on the RPM market to fulfill the Company's SSO capacity obligation beginning in PY15/16. As I mentioned earlier, it is PJM's responsibility to ensure that there is adequate capacity under the RPM construct to meet the capacity requirements of all the loads in PJM., Finally in this regard, Company witness Graves discusses the operation of PJM markets in more detail.

THE FUEL ADJUSTMENT CLAUSE (FAC)

Q. PLEASE REVIEW THE CURRENT FAC.

A. The Companies' current FAC began in 2009 as part of the 2009-2011 ESP. The FAC recovers the actual cost of fuel, purchased power, including capacity and other variable production costs such as environmental variable costs.

Q. PLEASE REVIEW THE ACCOUNTS INCLUDED IN THE CURRENT FAC.

A. The following is a list of accounts that are currently included in the FAC along with a brief description of each account.

- **501 Fuel** – This account includes the cost of fuel and transportation costs used in the production of steam for generation of electricity. For the Companies, this is the vast majority of variable costs associated with energy production. The fees associated with the FAC audit are also charged to this account.
- **502 Steam Expenses (Environmental subaccounts)** – This account includes the cost of material and expenses used in the production of steam for the generation of electricity. In recent years the majority of the expenses recorded in this account have been for chemicals used in environmental equipment such as selective catalytic reduction (SCR) equipment and flue gas desulfurization

(FGD) equipment. These chemicals are referred to as environmental consumables and include lime, limestone, trona, and urea. Lime and limestone are used in FGDs to remove sulfur from the post combustion process. Urea is the primary chemical agent used in the removal of NO_X. Trona is necessary to hinder the formation of SO_3, where an FGD and SCR are used in tandem. Any new environmental-related chemicals that may be required in the future will be included in the FAC.

- **509 Allowances** – This account records the cost of emission allowances to cover the emission of effluents such as SO_2 and NO_X.
- **518 Nuclear Fuel Expense** – This account includes the net amortization of the cost of nuclear fuel assemblies. The Companies do not own or operate a nuclear generating plant, are not currently incurring this cost, and are not expecting to incur this expense in the foreseeable future.
- **547 Fuel** – This account includes the cost of fuel used in facilities other than steam electric generation, such as a simple cycle gas peaking unit. Fuel costs for combined cycle gas plants are recorded in Account 501.
- **555 Purchased Power** – This account records the cost of electricity purchases including transactions under the AEP Pool and renewable energy contracts. It includes both energy and demand or capacity charges. PJM Interconnection L.L.C. (PJM) ancillary services that are recorded in Account 555 are not included in the FAC, but are included in the Transmission Cost Recovery Rider (TCRR).

- **507 Rents (Applicable subaccounts only)** – If a purchased power contract or unit power sale is required to be recorded as a lease per accounting rules, then the demand charge associated with the purchased power contract may be recorded in this account. Currently, there are no demand charges recorded in this account for the Companies.
- **557 Other Expenses (Power Supply – applicable subaccounts only)** – This account records the cost of renewable energy credits (RECs) to meet the renewable requirements of S.B. 221.
- **411.8 Gains from Disposition of Allowances and 411.9 Losses from Disposition of Allowances** – If gains or losses are experienced on the sale or other disposition of emission allowances, they are recorded in these accounts. Regular sales of allowances occur at the annual EPA auction resulting in gains each year. Sales to third parties are periodically made and settlements under the Federal Energy Regulatory Commission (FERC) approved AEP Interim Allowance Agreement (IAA) can result in gains and losses.
- **Other Accounts and subaccounts** – If environmental, fuel, purchased power and renewable expenses or taxes are recorded in accounts or subaccounts not specifically mentioned in this testimony, the Companies may include them in the FAC. For example a carbon tax could be implemented and recorded in a tax account. Clearly, such a federally mandated carbon or energy tax would be recoverable though the FAC.

Q. IS THE COMPANY PROPOSING TO CONTINUE THE FAC IN THIS ESP?

A. Yes, but only until the Company's SSO load is supplied through the auction process, which would begin January 1, 2015. At that time the Company will implement a rider which will recover the purchased power expense resulting from the auction for the load not served by a CRES. For the period from Corporate Separation until SSO load is supplied through the auction process, the Genco will bill AEP Ohio its actual fuel costs, in the same or similar form and detail as contained in current FAC monthly accounting done by AEP Ohio. In addition, the Company is proposing to modify the FAC by removing Account 557 and the REC expense from the fuel clause, and recovering REC expense through the new AER. In addition, bundled purchased power products, or REPAs, currently recorded in Account No. 555, will be split into their REC and non-REC components. The REC component will be recovered through the AER and the non-REC portion will continue to be recovered through the FAC. The AER will continue through the full term of the ESP. I will discuss the AER later in this testimony.

Q. IN ADDITION TO THE INFORMATION YOU HAVE ALREADY PROVIDED ON THE FAC, ARE YOU PROVIDING ANY ADDITIONAL INFORMATION PURSUANT TO O.A.C. 4901:1-35-03(C)(9)(a)?

A. Yes Exhibit PJN-4 provides additional information as specified in this section of the O.A.C., including the generating plants currently owned by AEP Ohio that the FAC cost pertains to and a narrative pertaining to the Company's procurement policies and procedures regarding FAC fuel costs, this information is applicable for the period before Corporate Separation occurs.

THE ALTERNATIVE ENERGY RIDER (AER)

Q. WHAT MECHANISM IS THE COMPANY PROPOSING FOR THE RECOVERY OF REC EXPENSE IN THIS ESP?

A. The Company is proposing to begin recovery of REC expense, associated with REPAs or acquired directly, via the AER starting with the implementation of this ESP. The energy and capacity portions of renewable energy would continue be recovered under the FAC, while it exists. After the FAC terminates, energy and capacity associated with the REPAs will be sold into the PJM market and netted against the total cost of the REPA, leaving only the residual REC expense to be recovered from SSO customers. The REC values will flow through the REC inventory and be charged to Account No. 557 (Other Power Supply Expense) which is used today for identified REC expense and is currently included in the FAC. The Company will recover the REC expense through the AER and, therefore, will no longer include this expense or account in the FAC. The REC expense recoverable by the AER is bypassable for those customers who switch to another supplier. The Company will make the quarterly filing of the AER in conjunction with the FAC, while it exists. After the FAC terminates, the Company will continue to acquire RECs to meet its renewable portfolio standards for its SSO load and will use the AER to recover the associated costs.

Q. IN THE COMPANY'S CORPORATE SEPARATION FILING, THE COMPANY IS PROPOSING TO LEAVE THE REPAS WITH OPCO AFTER CORPORATE SEPARATION. WILL THIS REDUCE THE AMOUNT OF ENERGY OR CAPACITY TO BE AUCTIONED?

A. No. The plan is for the Company to liquidate the energy and capacity in the PJM market. This sale of energy and capacity will offset fully the purchase of energy and capacity value of the REPA. Therefore, the full SSO load will be available to be auctioned. RECs which are a product separate from capacity and energy will not be sold as part of this transaction and will be available to the Company to meet its alternative energy requirements.

Q. HOW WILL THE REC EXPENSE BE DETERMINED WHEN PURCHASED AS PART OF A BUNDLED RENEWABLE PRODUCT (*I.E.,* REPA)?

A. To segregate the REC component of a REPA, the Company will allocate the purchase price into three components (energy, capacity, and REC value) using a residual method. The Company will use a monthly average PJM market price to value the energy component. Capacity will be valued using the price at which it can be sold into the PJM market. The remaining value would then be the cost of the REC. A simple (residual) example, using hypothetical values for unbundling a REPA of $70/ Mwh is outlined below.

Delivered Unit	Market Value $/Mwh
Energy	$35 (LMP)
Capacity	$12
REC	$23 (Remaining value)
Total	$70

Q. WOULD THE IMPLIED REC VALUE RESULTING FROM THE ABOVE DESCRIBED METHOD ALSO BE THE REC VALUE USED FOR THE PURPOSES OF CALCULATING THE 3% COST CAP?

A. Yes, for consistency the Company submits that the same implied REC value should be used for the cost cap calculation under rule 4901:1-40-07 O.A.C.

<u>**GENERATION RESOURCE RIDER (GRR)**</u>

Q. PLEASE DESCRIBE THE GRR RIDER BEING PROPOSED BY THE COMPANY IN THIS FILING.

A. AEP Ohio is proposing to establish a nonbypassable rider which will recover the cost of new generation resources, including renewable capacity that the Company owns or operates for the benefit of Ohio customers. This rider is nonbypassable and will be designed to recover renewable and alternative capacity additions, as well as more traditional capacity constructed or financed by the Company and approved by the Commission. The GRR will be used for recovery of the proposed Turning Point project, if approved by this Commission. It is not expected that there will be any additional projects included in the rider during the term of this ESP.

Q. IS THE COMPANY SEEKING APPROVAL OF THE PROPOSED NON-BYPASSABLE CHARGE ASSOCIATED WITH THE TURNING POINT PROJECT AS PART OF THIS CASE?

A. No. The Company will be seeking the Commission's approval of the non-bypassable charge for the life of the proposed Turning Point project in a separate proceeding after the Commission determines the need for the facility in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR and establishes the GRR as requested in this proceeding. For now, the GRR would be a placeholder rider established at level of zero.

POOL TERMINATION PROVISION

Q. PLEASE DESCRIBE THE STATUS OF THE AEP POOL.

A. On December 17, 2010 AEP Ohio and other members of the AEP Pool provided written notice to each other of their mutual desire to terminate the existing agreement on three years notice in accordance with Article 13.2. The Interim Allowance Agreement (IAA) would be terminated concurrently with the AEP Pool. Shortly after the filing of this ESP, AEPSC on behalf of the operating companies that are members of the AEP Pool will make a filing with the FERC notifying it of the members' intention to terminate the AEP Pool on January 1, 2014. Concurrent with the AEP Pool termination AEP Ohio plans to implement its Corporate Separation plan. The requested Corporate Separation will be filed with this Commission in a separate proceeding as previously discussed. OPCO's current share of Amos unit 3 and both Mitchell units will subsequently be transferred to APCo and Kentucky Power upon receiving the necessary state and federal approvals.

Q. WHY IS THE TERMINATION OF THE AEP POOL AND IMPORTANT ISSUE FOR THE COMPANY?

A. A significant portion of AEP Ohio's total revenues come from sales of power to other Members of the AEP Pool. With the termination of the AEP Pool, the Company will need to find new or additional revenue to recover the costs of its generating assets, or reduce the cost of those assets. The Capacity payments received by AEP Ohio cannot be mitigated by opportunity sales in the market alone. The Company is therefore proposing an opportunity to make a subsequent application with this Commission, if needed to recover lost revenues as part of the move to competitive markets.

Q. IS THE COMPANY SEEKING COMPENSATION FOR THE LOSS OF AEP OHIO'S CAPACITY REVENUE AS A RESULT OF THE AEP POOL TERMINATION.

A. No, unless the Corporate Separation plan, including the plan for the Amos and Mitchell unit transfers, is not approved and implemented. The transfer of these units is one of the Companies principal methods of mitigating the financial harm to the Genco from the termination of the AEP Pool. If the transfer of these units occurs, less revenue is needed by the Genco, since it will no longer incur the expenses associated with these units. The megawatts associated with AEP Ohio's share of Amos 3 and the Mitchell units are equivalent to the amount of megawatts sold in the last two years to other members of the AEP Pool.

Q. HOW WOULD THE PROPOSED POOL TERMINATION PROVISION WORK?

A. If the Company's requested Corporate Separation plan is approved as filed, then this provision is not triggered and the Company agrees not to make any subsequent filing under this provision. If the Corporate Separation plan is denied or amended then the Company would be permitted to charge a nonbypassable rate to compensate it for any loss of earnings associated with the AEP Pool termination. That compensation would be determined in a subsequent filing made under this ESP. In general, the Company will compare the lost AEP Pool capacity revenue to increases in net revenue related to new wholesale transactions or decreases in generation asset costs that result from the

AEP Pool termination. If there is substantial decrease in net revenue then the Company may avail itself of this provision and seek recovery of the lost net revenue from retail customers.

Q. IF THE AEP POOL TERMINATION PROVISION IS INVOKED, WHAT PERIOD WILL THE COMPANY USE TO DETERMINE THE SUBSTANTIAL HARM TO THE COMPANY

A. The annual effect will be determined by comparing the actual AEP Pool capacity revenue in the most recent twelve-month period preceding the effective date of the change in the AEP Pool, to increases in net revenue related to new wholesale transaction or decreases in generation asset costs using that same twelve-month period.

Q. IS THE COMPANY PROPOSING A THRESHOLD AMOUNT UP TO WHICH IT WILL BEAR THE COST OF TERMINATING THE POOL AND NOT SEEK ANY RECOVERY FROM CUSTOMERS UNDER THIS PROVISION?

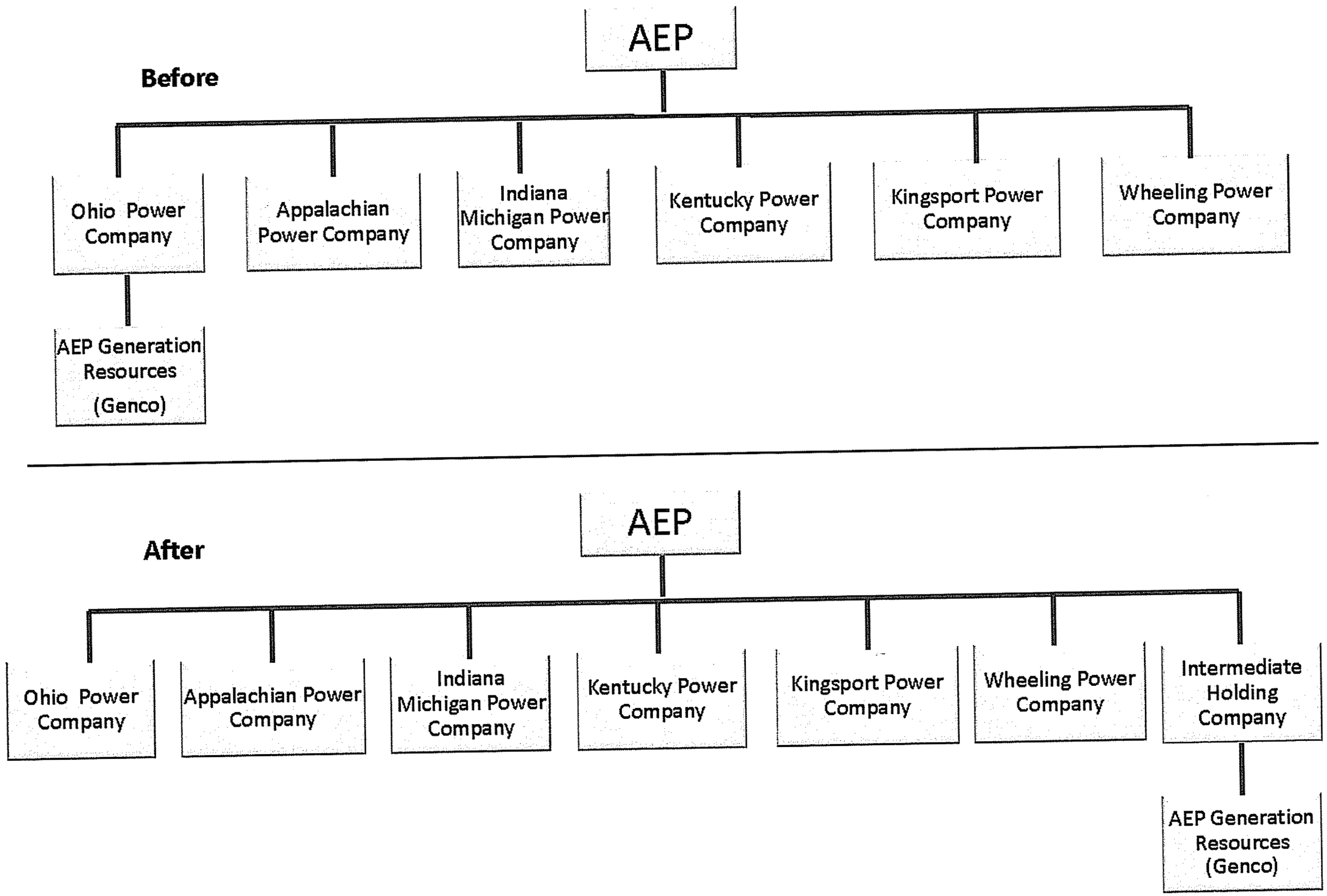
A. Yes. The Company will not adjust the proposed ESP rates if the annual effect of the AEP Pool termination or any new affiliate arrangement is less than $35 million on an annual basis during the term of this ESP.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Exhibit PJN-1

Corporate Structure Before and After Corp. Sep.



AEP East Generating Unit Retirements

Estimated to be Retired by June 1, 2015

Plant	Location	Unit	MW AEP Ohio	MW Other AEP East Cos.
Conesville*	Conesville, OH	3	165	
Big Sandy	Louisa, KY	1		278
Clinch River	Cleveland, VA	3		235
Glen Lyn	Glen Lyn, VA	5,6		335
Kammer Plant	Moundsville, WV	1,2,3	630	
Kanawha River	Glasgow, WV	1,2		400
Muskingum River	Beverly, OH	1,2,3,4	840	
Beckjord**	New Richmond, OH	6	54	
Picway	Lockbourne, OH	5	100	
Philip Sporn	New Haven, WV	1,2,3,4	300	300
Tanners Creek	Lawrenceburg, IN	1,2,3		495
			2,089	2,043

*Expected retirement 12/31/2012
**Plant operated by Duke Power Company

UNIT RETIREMENTS AS A PERCENT OF FOSSIL CAPACITY

(**FOSSIL** *excludes nuclear, hydro, pumped storage, wind, and solar.*)

	Nominal Capability (MW)				
	APC	I&M	KPC	OPC**	Total
Total Generation* Before Transfers	6,567	3,397	1,471	15,151	26,586
Transfers*** Proposed in FERC Filing	2,115	-	312	(2,427)	-
Total Generation After Transfers	8,681	3,397	1,783	12,724	26,586
Upcoming Retirements****	(1,270)	(495)	(278)	(2,089)	(4,132)
Total Generation After Transfers	7,411	2,902	1,505	10,635	22,454
Retirement % Before Transfers	19%	15%	19%	14%	16%
Retirement % After Transfers	15%	15%	16%	16%	16%

*Includes CD2, CD3, Mone, OVEC and Lawrenceburg entitlements of approximately 3900 MW.

**AEP Generation Resources owns the generating assets post corporate separation

***A portion of the unit transfers (350 MW) is related to the transfer of Wheeling Power's load from OPC to APC

****Sporn 5 was retired February 13, 2012

Other Notes:
Current planning includes an FGD for Big Sandy unit 2 (KPC) in 2016 and an SCR and FGD for Rockport unit 1 (I&M and KPC) in 2016. BS2 is 800 MW and RPT1 is 1320 MW

Nominal capability is typically higher than summer capability

Exhibit PJN-3

Average Monthly Sales & Purchases Of Capacity Among Members Of the AEP Power Pool For 2010 and 2011

Company	Member Actual Capacity kW	Member Required Capacity kW	Sales (Purchases) To/From Other Members Capacity kW
2010			
Appalachian Power	6,361,758	8,855,942	(2,494,183)
Kentucky Power	1,468,583	1,827,208	(358,625)
Indiana Michigan Power	5,429,917	5,071,625	358,292
AEP Ohio	13,338,750	10,844,233	2,494,517
Total	26,599,008	26,599,008	-
2011			
Appalachian Power	6,377,000	8,467,642	(2,090,642)
Kentucky Power	1,471,000	1,786,900	(315,900)
Indiana Michigan Power	5,428,000	5,173,583	254,417
AEP Ohio	13,176,333	11,024,208	2,152,125
Total	26,452,333	26,452,333	-

INFORMATION PROVIDED PURSUANT TO OAC 4901:1-35-03(C)(9)(a)

General Fuel Requirements

The generating units of OPCo (AEP Ohio) and the other AEP System- East Zone operating companies, which are predominantly coal-fired, are managed to ensure adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. American Electric Power Service Corporation (AEPSC), acting as agent for AEP Ohio, is responsible for the procurement and delivery of fuel and chemicals used for environmental compliance (consumables) to AEP Ohio's generating stations. AEPSC's primary objective is to assure a continuous supply of quality fuel at the lowest cost reasonably possible. Deliveries are arranged so that sufficient fuel and consumables are available at all times. The quality of the delivered coal is fundamental to achieving and maintaining compliance with the applicable environmental limitations and operating efficiencies.

AEP Ohio passes any net gains on the sale of emission allowances through the FAC. AEP does not have a practice of re-selling coal contracts, however, if it did so it would pass any cost savings or profits related to Ohio generating resources through the FAC.

Coal and Gas Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. Sources of coal are determined by taking into account contractual obligations and existing sources of supply. AEP Ohio's total coal requirements are met using a portfolio of long-term arrangements and

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spot-market purchases. Long-term contracts support a relatively stable and consistent supply of coal. Spot purchases are used to provide flexibility in scheduling contract deliveries, to accommodate changing demand, and to cover shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases are also made to test-burn any promising and potential new long-term sources of fuel in order to determine their acceptability as a fuel source in a given power plant's generating units.

All long-term and most spot purchases of coal for AEP Ohio's plants are made based on the evaluation of competitive bids. Additional short-term purchases are made based on an evaluation of offers (both solicited and unsolicited) from suppliers compared to current published market prices as well as other offers for tonnage of acceptable quality. In all cases, the goal is securing the lowest reasonable delivered price on a cents-per-million-BTU basis.

AEP Ohio's day-to-day needs for natural gas are generally unpredictable and are generally purchased on a day-ahead and intra-day basis as needed for peaking requirements. Natural gas is competitively purchased and primarily obtained in the spot market with prices on a daily index or a daily fixed price. The Company has arranged for both firm and interruptible transportation service from various inter-state pipelines, which provide flexible supplies from multiple production areas.

<u>Inventory</u>

AEP Ohio attempts to maintain in storage at each plant an adequate coal and consumables supply to meet normal burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, the Company attempts to conserve coal supplies. In the event of a severe coal shortage, AEP Ohio and the AEP System-East Zone operating companies would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan [is this affected by CS].

Generating Unit Information

The generating units that AEP Ohio owns are included in the table below. The table also lists major environmental equipment that has been added to the units: Flue Gas Desulfurization (FGD) for the control of SO_2 emissions, and Selective Catalytic Reduction (SCR) for the control of NO_X emissions. The costs associated with these generating units are included in the FAC as set out in the Company's testimony in its ESP filing.

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AEP Ohio Owned Generating Units
(March 15, 2012)

Plant	Unit No.	Fuel	Location	SCR	FGD
Cardinal	1 (Note A)	Coal	Brilliant, OH	√	√
Conesville	3	Coal	Conesville, OH		
Conesville	4 (Note B)	Coal	Conesville, OH	√	√
Conesville	5	Coal	Conesville, OH		√
Conesville	6	Coal	Conesville, OH		√
Darby	1-6	Gas	Mount Sterling, OH		
Gen. J.M. Gavin	1	Coal	Cheshire, OH	√	√
Gen. J.M. Gavin	2	Coal	Cheshire, OH	√	√
J.M. Stuart	1 (Note B)	Coal	Aberdeen, OH	√	√
J.M. Stuart	2 (Note B)	Coal	Aberdeen, OH	√	√
J.M. Stuart	3 (Note B)	Coal	Aberdeen, OH	√	√
J.M. Stuart	4 (Note B)	Coal	Aberdeen, OH	√	√
John E. Amos	3 (Note C)	Coal	Winfield, WV	√	√
Kammer	1	Coal	Moundsville, WV		
Kammer	2	Coal	Moundsville, WV		
Kammer	3	Coal	Moundsville, WV		
Mitchell	1	Coal	Moundsville, WV	√	√
Mitchell	2	Coal	Moundsville, WV	√	√
Muskingum River	1	Coal	Waterford, OH		
Muskingum River	2	Coal	Waterford, OH		
Muskingum River	3	Coal	Waterford, OH		
Muskingum River	4	Coal	Waterford, OH		
Muskingum River	5	Coal	Waterford, OH	√	
Philip Sporn	2	Coal	New Haven, WV		
Philip Sporn	4	Coal	New Haven, WV		
Picway	5	Coal	Lockbourne, OH		
Racine	1-2	Hydro	Racine, OH		
W.C. Beckjord	6 (Note B)	Coal	New Richmond, OH		
Waterford	1-4	Gas	Waterford, OH	√	
William H. Zimmer	1 (Note B)	Coal	Moscow, OH	√	√

Note A — The Cardinal Plant consists of three coal-fired steam units, with Unit No. 1 owned by Ohio Power and Unit Nos. 2 and 3 owned by Buckeye Power, Inc. ("Buckeye").

Note B — Ohio Power jointly owns several units with Duke Energy Ohio, LLC and Dayton Power and Light Co. The jointly-owned units are Conesville 4, Stuart 1-4, Beckjord 6 and Zimmer 1. Stuart Diesel units 1-4, which are not listed above, will also transfer to AEP Generation Resources.

Note C — Ohio Power owns two-thirds and APCo owns one-third of Amos Unit No. 3.

Note: — Ohio Power also has certain contractual entitlements to purchase power, which will transfer to AEP Generation Resources.

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Purchased Power

AEP Ohio makes power purchases from affiliates, non-affiliated companies and through the PJM market that will be included in the Companies' proposed FAC. AEP Ohio has contracts to purchase power from OVEC and Buckeye Power generating units, and from its affiliate, American Electric Generating Company's (AEG) Lawrenceburg plant.

AEP Power Pool and PJM

The FAC reflects the AEP Ohio generating resources being operated under the AEP Interconnection Agreement until its expected termination. AEP is a member of PJM and operates its fleet, including AEP Ohio's generating resources, in accordance with PJM protocols.

Economic Dispatch

AEP, along with other generators in PJM, "offer(s)" available generating units into the PJM market on a daily basis. PJM performs an economic dispatch for the PJM footprint to meet the load requirements with all available generation. After the end of the month AEP reconstructs, for cost allocation purposes, the economic dispatch for its units based on hourly generating unit output. This reconstruction assigns the resources used for Off-System Sales for each hour of the month. The resources at the top of the stack, i.e., those with higher variable costs, are assigned to Off-System Sales resulting in lower costs assigned to internal load customers.

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Corporate Separation

The Company's current ESP term covers a period that includes AEP Ohio operating as a bundled utility, with its own generation resources, and as a member of the AEP Pool. The ESP term also encompasses the period after the termination of the AEP Pool and the Corporate Separation of non-T&D assets and liabilities from AEP Ohio. The forgoing primarily describes the operation of AEP Ohio as a bundled utility.

Some of the major changes to the previous narrative are discussed below. The generation assets listed in the table for existing generation will no longer be owned or operated by AEP Ohio. There will not be any AEP Pool transactions that affect the FAC after termination of the AEP Pool. There will be a purchased power contract with AEP Generation Resources Inc. (Genco) to supply the SSO load requirements of AEP Ohio after Corporate Separation and prior to the auction of that load. Once suppliers begin serving AEP Ohio's retail SSO load as a result of the auction, the purchased power contract with the Genco ends and purchased power contracts between AEP Ohio and the winning wholesale auction bidders begin. More detail of these transactions is contained in the Corporate Separation filing to be made with this Commission and the upcoming filings to be made with the Federal Energy Regulatory Commission.

EXHIBIT _____

INDIANA MICHIGAN POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to
Commission Rule 170 IAC 4-7

November 1, 2011

SC EXHIBIT 16

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VOLUME I

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EXECUTIVE SUMMARY

Executive Summary

Indiana Michigan Power Company's (I&M, or "the Company") energy and peak requirements are expected to grow at 0.3% and 0.4% per year, respectively, through 2031. To meet these requirements, I&M analyzed three distinct resource portfolios – 1) one plan that retrofits its larger coal units at Rockport and Tanners Creek to meet new and proposed environmental mandates (Base Plan); 2) a plan that retires Tanners Creek 4 in 2015 and replaces it with a natural gas combined cycle facility in 2017 (Gas Plan), and finally 3), a plan that meets I&M's energy requirements assuming Tanners Creek 4 is retired, and replaces it with market purchases (Market Plan.)

The Base Plan maintains the capacity of Rockport 1 and 2, Tanners Creek 4, and the two Donald C. Cook Nuclear Plant units. Tanners Creek 1-3 are assumed to be retired by December 31, 2014. Renewable capacity and demand response/energy efficiency programs are expanded in the Base Plan. This Base Plan is expected to have a lower cost to customers through 2040, on a cumulative present value basis, than the Gas or Market plans. The Base Plan allows the Company to meet its customer's energy requirements, emission reduction requirements and energy efficiency mandates without subjecting customers to significant risk. The supply-side expansion plan represented in the Base Plan reflects I&M's commitment to DSM programs and compliance with energy efficiency mandates, renewables, and to the need for compliance with environmental regulations.

AEP-East Pool Status

On December 17, 2010, pursuant to Article 13 of the Federal Energy Regulatory Commission (FERC)-approved AEP Interconnection Agreement ("IA," "Interconnection

Agreement" or "AEP Pool"), each of the AEP Pool members gave written notice to the other members, and to American Electric Power Service Corporation ("AEPSC"), the AEP Pool's agent, of its intent to allow for modification-including the possibility of termination- of the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC[1]. Because the IA is a rate schedule on file at FERC, its modification, and possible termination, will not be effective until accepted for filing by FERC.

The Interim Allowance Agreement among the AEP companies ("IAA"), which was most recently modified in 1996 and deals with sulfur dioxide (SO_2) emissions and allowances, would likely be terminated. Environmental regulations have expanded beyond those intended to be covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_X). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions.

Environmental Compliance Issues

The 2011 Integrated Resource Plan (IRP) considers final and proposed future United States Environmental Protection Agency (EPA) regulations that will impact fossil-fueled electric generating units (EGU).

The EPA has issued final rulemaking to replace the former Clean Air Interstate Rule (CAIR) for the regulation of SO_2 and NO_X which had previously been remanded by

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[1] The timing of the modification or termination of the IA may be affected by the Stipulation pending before the Public Utilities Commission of Ohio in (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO), which, if approved, would require the generating assets in Ohio to be placed in a separate corporation and result in the filing at the FERC to be made in early 2012.

the federal courts. The EPA issued the Cross-State Air Pollution Rule (CSAPR) to establish state-specific emission budgets for SO_2 and both annual and seasonal (May-September) NO_X with a two-phase emission reduction beginning in 2012. Further, the EPA proposed the EGU Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the court vacated Clean Air Mercury Rule (CAMR). As proposed, the EGU MACT rule will regulate emissions of hazardous air pollutants (HAPs) such as mercury, arsenic, chromium, nickel, certain acid gases and organic HAP compounds and is expected to be finalized in December 2011 with full implementation in 2015. The EPA is also expected to propose first-ever requirements regulating greenhouse gas emissions as early as later this year, but the substance of those requirements is not known. Combined, the CSAPR, EGU MACT rule, and other impending federal air regulatory programs will require significant emission reductions from all U.S. coal and lignite-fired units. Emission reductions will be achieved beginning in 2012 as a result of unit retirements, unit curtailments, and installation of emission control technologies, including flue gas desulphurization (FGD) or dry sorbent injection (DSI), selective catalytic reduction (SCR), activated carbon injection (ACI), and fabric filter systems (FF).

In addition, a new rule on the handling and disposal of coal combustion residuals (CCR) is being developed by the EPA, which, as proposed, would require significant additional capital investment in coal-fired EGU necessary to convert "wet" ash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to "dry" systems and in addition build waste-water treatment facilities to process plant groundwater run-off before discharge. EPA is also developing regulations with respect to the intake of cooling water and discharge of wastewater, which has the potential to require significant capital investment for compliance in the future.

The cumulative cost of complying with these final and proposed environmental rules will be highly burdensome to I&M, the AEP-East operating companies, and their customers. Such requirements will also accelerate environmental equipment retrofits and proposed retirement dates of any currently non-retrofitted coal unit in I&M and the AEP-East fleet.

The analyses used in developing this IRP assume that greenhouse gas (GHG) legislation or regulation will eventually be implemented. However, rather than a more comprehensive cap-and-trade approach, it is assumed that the resulting impact would be in the form of a proxy of CO_2 "tax" which would take effect in the approximate 2022 timeframe. The cost of CO_2 is expected to stay within the $15-$30/tonne range over the long-term analysis period; however, a higher cost CO_2 sensitivity case was also developed to test the impact of a literal doubling of CO_2 prices on the plan selection decision.

Summary of I&M and AEP-East Resource Plans

An IRP explains how a utility company will meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. By Indiana rule, I&M is required to provide an IRP that encompasses a 20-year forecast period.

Specific I&M capacity additions are listed in Figure 1 and their relative impacts to I&M's capacity position are shown on Figure 2. Accordingly, AEP-East capacity additions are listed in Figure 3 and their relative impacts to AEP-East's capacity position are shown on Figure 4. For I&M this includes the construction or acquisition of additional intermediate capacity as well as additional wind purchases to meet both voluntary and mandated renewable goals established in the I&M service territory. Figure 1 also shows that I&M requires **NO** market purchases to meet minimum reserve criteria in PJM. Figure 2 illustrates the importance of DR/EE to I&M, the level for which are largely established pursuant to achieving known state-specific DR/EE mandates.

Figure 1

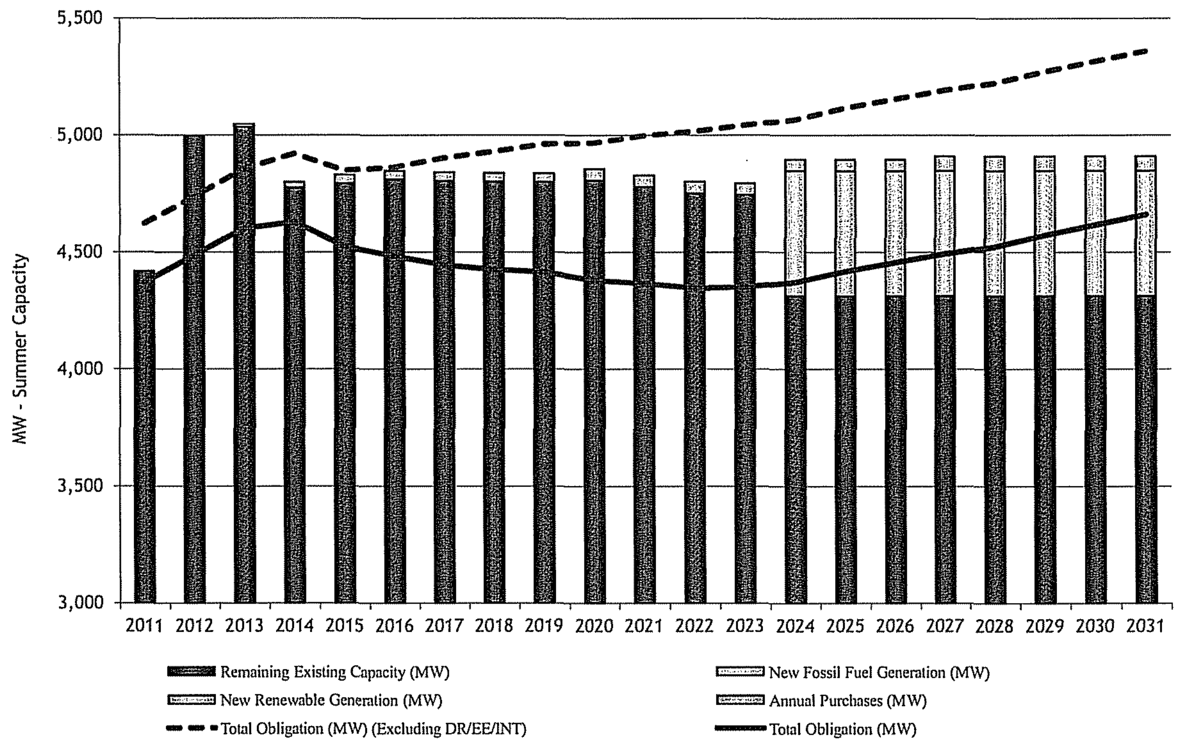
I&M Resource Plan to Meet PJM Reserve Margin Requirements

I&M Capacity Portfolio (Stand-Alone View)

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12						14	258	
2012 /13						23	258	
2013 /14			100	13		49	258	
2014 /15	(485)		100	13		123	258	0
2015 /16			100	13		186	258	0
2016 /17						249	258	0
2017 /18						313	258	0
2018 /19						353	258	0
2019 /20						389	258	0
2020 /21		30	100	13		408	258	0
2021 /22						412	258	0
2022 /23						415	258	0
2023 /24						418	258	0
2024 /25	(500)				562	419	258	0
2025 /26						423	258	0
2026 /27						423	258	0
2027 /28			100	13		423	258	0
2028 /29						422	258	0
2029 /30						423	258	0
2030 /31						423	258	0
2031 /32						423	258	0
	(985)	**30**	**500**	**65**	**562**	**423**	**258**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

Figure 2
I&M PJM Capacity Position



In order for AEP-East to maintain its minimum PJM reserve requirement, market purchases, as outlined in Figure 3, are needed as early as the 2014/2015 PJM "planning year". It has been assumed that this purchased capacity would be assigned to AEP-East companies under the existing AEP Pool construct. Under that construct any *short-term* market purchases are allocated to all the AEP-East companies based on their Member Load Ratio (MLR) and, therefore, will **NOT** affect the respective companies' capacity position in the AEP Pool.

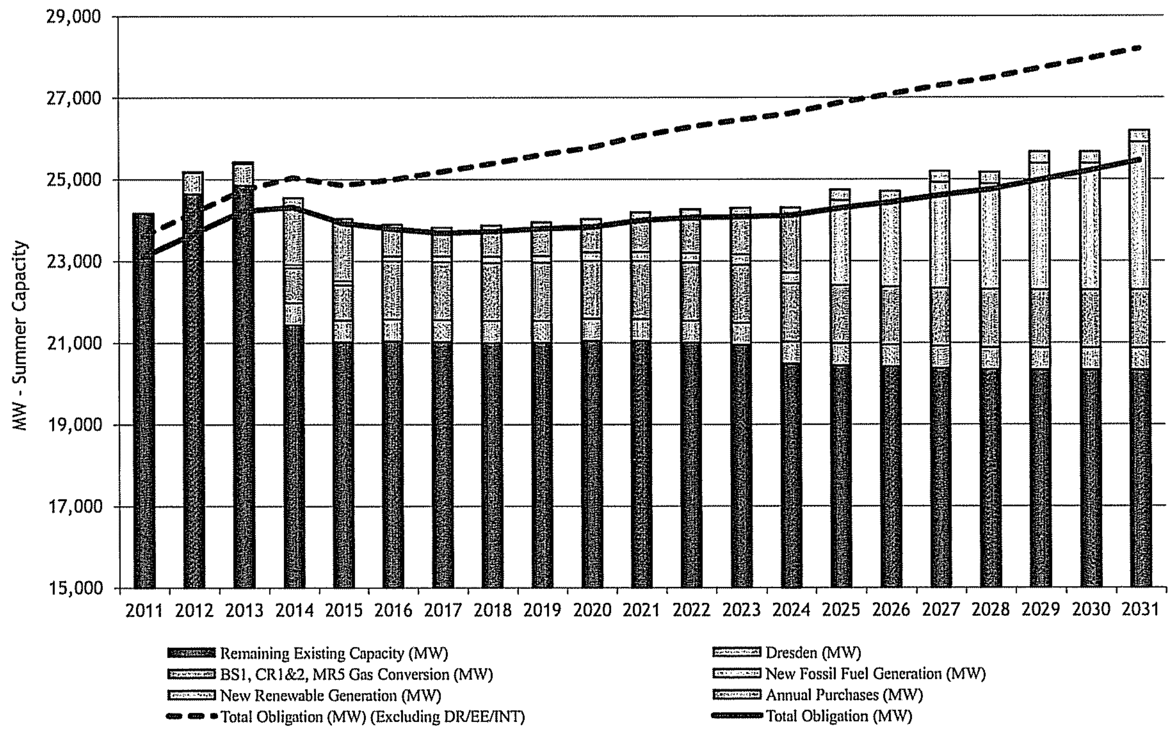
Figure 3

AEP-East Resource Plan to Meet PJM Reserve Margin Requirements

AEP-East Capacity Portfolio								
Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12		(10)				123	519	0
2012 /13	(560)		117	20	580	199	519	0
2013 /14			120	21		302	519	0
2014 /15	(3,747)	(136)	232	38		570	519	1,776
2015 /16	(278)		215	32		823	519	1,643
2016 /17			150	20	602	1,100	519	843
2017 /18			150	20		1,365	519	757
2018 /19			117	20		1,478	519	823
2019 /20			100	13		1,617	519	888
2020 /21		35	271	40		1,765	519	885
2021 /22			100	13		1,870	519	1,052
2022 /23			100	13		1,955	519	1,158
2023 /24			200	26		2,026	519	1,230
2024 /25	(500)		21	8		2,080	519	1,718
2025 /26					2,236	2,130	519	0
2026 /27						2,142	519	0
2027 /28			100	13	550	2,142	519	0
2028 /29			50	7		2,140	519	0
2029 /30					550	2,142	519	0
2030 /31						2,142	519	0
2031 /32					562	2,142	519	0
	(5,085)	**(111)**	**2,043**	**301**	**5,080**	**2,142**	**519**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

Figure 4
AEP-East PJM Capacity Position



This IRP provides for reliable electric utility service, at reasonable cost, through a combination of traditional supply, market (purchased power) options, renewable supply and demand side programs. I&M and AEP-East will provide for adequate capacity resources to serve their customers' peak demand and required PJM reserve margin needs throughout the forecast period.

Conclusion

This IRP is being presented at a time of great uncertainty with regard to the future status of I&M's relationship to the other AEP-East generating companies. The AEP Pool construct, which has been in place since 1951 (with modifications over time) will likely be modified, or potentially terminated, by 2014 or sooner. The final outcome of pending environmental regulations may require a significant level of capacity retirements in a relatively short period of time. The final outcome of this uncertainty makes it a challenge to commit to large capital investments in new generating capacity in the near term. Over the next six to twelve months, environmental rules will be finalized and AEP Pool negotiations will be underway, and that may provide a higher level of certainty with regard to actions the Company should embrace. Until that certainty is realized, the Company's plan is to maintain optionality and flexibility in meeting the requirements of its customers.

Therefore, in this IRP, future market purchases for AEP-East over this 20-year forecast period ideally represent initial "placeholders" for such incremental capacity resource needs. It is the Company's intent to continually investigate and analyze the economic merits of future opportunities to build or acquire "owned-resources" in lieu of market purchases to ensure greater (local) electrical reliability and price certainty for its customers. However, it should be considered that in the PJM region, most load serving entities (LSE) receive capacity through the market construct known as the Reliability Pricing Model (RPM) auction process. So while the concept of relying on the market may not be the approach chosen by the AEP-East operating companies, it is an accepted practice for many utilities in the region.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. In light of the current economic conditions and the movement towards increasing use of renewable generation and end-use energy efficiency, as well as known and proposed environmental rulemaking to further control fossil plant emissions which could result in the retirement, conversion, or retrofit of existing generating units, supply of capacity and energy to I&M will continue to be impacted. The resource planning process is becoming increasingly complex when considering pending legislative and regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and energy efficiency advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on I&M customers will be a primary consideration in this report.

1) SYNOPSIS

1. Synopsis

A. Overview

I&M serves 586,000 customers in Indiana and Michigan, including 458,000 in eastern and north central Indiana. I&M also sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives, and non-utility entities engaged in the wholesale power market. Its headquarters is in Fort Wayne, with external affairs offices in Indianapolis and Lansing, Michigan.

I&M maintains over 5,300 miles of transmission lines, including 615 miles of 765 kV lines – part of the extensive American Electric Power (AEP) network considered by many to be the backbone of the eastern U.S. transmission grid. I&M also operates over 20,000 miles of distribution lines and approximately 6,000 megawatts (MW)[2] of nominal generation. The Company operates two coal-fired generation plants, Rockport and Tanners Creek; Michigan's largest nuclear facility, Cook Plant; and six hydroelectric generating stations along the St. Joseph River – two in Indiana and four in Michigan.

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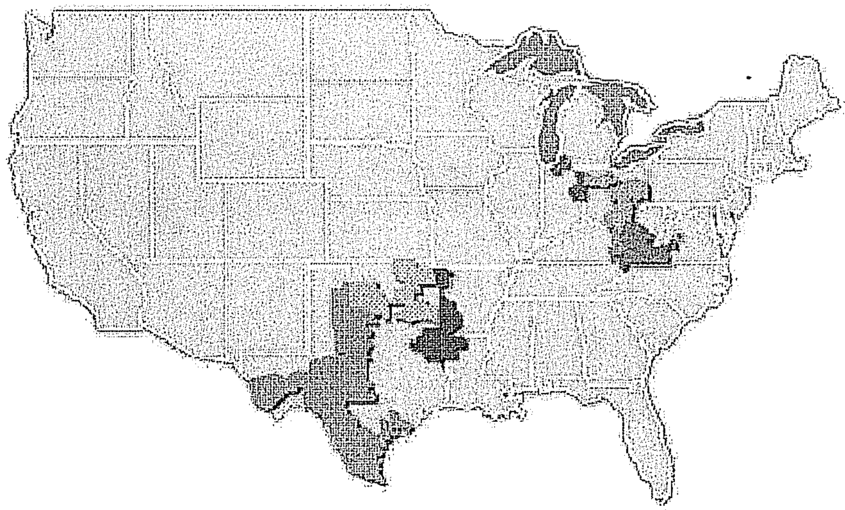
[2] Includes AEP Generating Company's (AEG) share of Rockport 1310 MW.



The AEP System

This Integrated Resource Plan (IRP) presents the electrical load forecast for I&M for the period 2011-2031, a resource analysis covering the period 2012-2031, and the resulting plan for I&M. The plan includes descriptions of assumptions, study parameters, methodologies, and consideration of both supply-side resources and demand-side management (DSM) programs.

As illustrated throughout the chapters of this report, I&M's resources, including its transmission system, are adequate.

B. Process

The planning process comprises several steps, including a forecast of load, consideration of reliability criteria, assessment of current resources, review of existing, and potential supply-side and demand-side resources, and a selection of an optimal plan, including risk assessment. To I&M's benefit, this process is carried out by various work groups drawing upon diverse knowledge and various areas of expertise. Many internal working groups have contributed to the I&M plan, led by a core multidisciplinary team with a combined total of 134 years of experience in IRP analysis. Additionally, these functional groups were assisted by several outside consulting organizations, bringing an independent view to I&M's plan.

Core Indiana IRP Team

Member	Current Job Title	Area of Expertise	Years of IRP Expertise*
Scott Weaver	Managing Director - Resource Planning & Operational Analysis	Overview-Supply/Demand	8
John Torpey	Director - Integrated Resource Planning	Resource Planning Development	4
Jon MacLean	Manager - Resource Planning	Supply-Demand and Other Factor Integration	35
Mark Becker	Manager - Resource Planning Modeling	*Strategist*® Optimization Modeling	28
William Castle	Director - Resource & DSM Planning	Demand-Side Management	5
Randy Holliday	Staff Economist	Energy & Demand Forecasting	26
John McManus	VP-Environmental Services	Environment Compliance	20
Kamran Ali	Manager Transmission Planning	Transmission Planning	4
Brian West	Regulatory Case Manager	IRP Project Coordinator	1

*These years are the years of IRP expertise, not necessarily the total years of service by the employee in the utility industry.

The current IRP was scrutinized using a number of sensitivity tests and I&M is confident that the plan will provide substantial guidance regardless of what scenarios may unfold. Several scenarios were analyzed for the purposes of this report. Scenario and sensitivity analysis is described in several areas of the 2011 report. See Chapter 3G, Forecast Uncertainty and Range of Forecasts, as it pertains to Energy and Demand Forecasts; and Chapter 8 for a discussion of commodity pricing scenarios as well as Chapter 8D and Chapter 8E for a discussion on Risk and Sensitivity analysis.

The Company continues to use proprietary data and programs in its IRP process. To highlight a few examples, the Company uses:

- *Strategist*® to optimize its plan and alternatives and risk assessment, and
- PROMOD IV® and PCI GENTRADER® for short and long-term production cost simulations, and
- *Aurora*^{XMP}, for portfolio risk simulation analysis.

Generally, these are industry accepted, often proprietary, software modeling tools.

Additionally, in Chapter 3 various models and data sources are utilized such as ARIMA models (see Chapter 3C) and SAE models (also Chapter 3C) as well as Moody's Analytics and DOE data.

The Company uses consultants and industry sources when deemed appropriate. For example, assumptions incorporated in the DSM analysis stem from the *Indiana Market Potential Study* performed by Forefront Economics and the *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.*, authored by the Electric Power Research Institute (EPRI). These, or similar, studies provide targeted, credible data necessary to inform critical assumptions.

C. Supply-Side Assessment

In the planning process several major drivers impact I&M's supply-side resources, namely:

- The age of the fossil-fueled generation fleet;
- the impact of final and proposed future United States Environmental Protection Agency (EPA) regulations, State legislated renewable portfolio standards (RPS) or voluntary Clean Energy initiatives; and
- the current mix of capacity which relies heavily on baseload generating assets.

I&M's requirements are influenced by the terms of the AEP pool agreement (see Chapter 2A and Chapter 5B). This IRP tentatively states that I&M will not add any major new baseload generation during the 2012-2031 forecast period. However, I&M will see an increase in both its DSM and renewable (Wind) programs as I&M continues to comply with mandatory, and conform with voluntary alternative/renewable resource requirements. As a result, even with the proposed retirements of Tanners Creek 1-3, I&M will not need to add any additional traditional capacity until late in the forecast period. The IRP does require that I&M add a 562 MW (summer rating) natural gas combined cycle (NGCC) when Tanners Creek 4 is retired. Exhibit 8-10 shows that I&M has positive reserve margins through the end of the forecast period.

D. Environmental

I&M has developed an IRP that not only allows the Company to meet future resource needs in a reliable and cost effective manner, but also one that considers final and proposed environmental rulemaking and the impacts to existing as well as planned facilities.

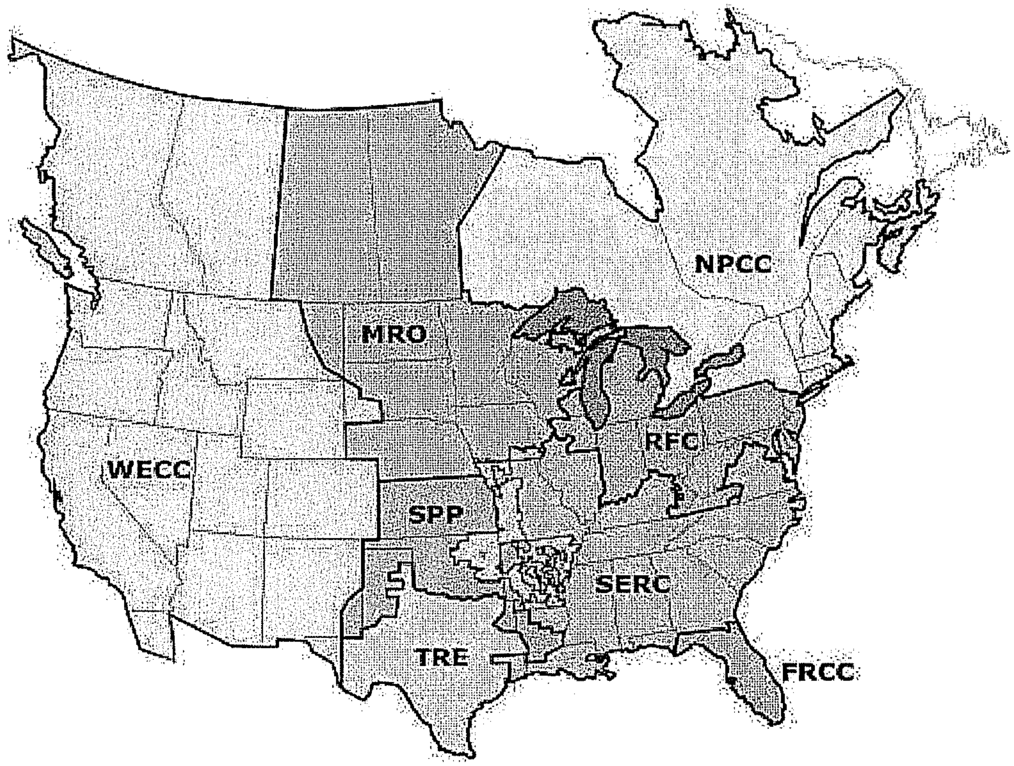
Because I&M's installed generation is nearly 40 percent nuclear, I&M and its customers have less risk exposure to environmental challenges that may threaten other EGUs. I&M has already implemented a number of pollution control projects to minimize the residual environmental effects of solid and hazardous waste at its facilities and to comply with existing and former air emission regulations, such as with the Title IV acid rain and the NO_X SIP Call programs.

Even with reduced risk exposure I&M faces a variety of environmental compliance challenges with the finalized CSAPR, the New Source Review (NSR) Consent Decree and the proposed EGU MACT rule. In addition, I&M will face regulations surrounding changes to power plant cooling water intakes, the requirements for handling and storage of coal combustion residuals, and potential regulations related to GHG emissions. Moving into the future, I&M will continue to meet these environmental compliance challenges

E. Transmission

I&M operates in Reliability*First* Corporation (RFC), a Regional Entity of the

North American Electric Reliability Corporation (NERC).



Source: http://www.nerc.com/regional/

On October 1, 2004, the AEP System-East Zone became part of the PJM Regional Transmission Organization (RTO) and began participating in the PJM energy market.

I&M transmission, part of the AEP integrated transmission system, together with the transmission systems of other PJM members, is planned on a regional basis via PJM's Regional Transmission Expansion Plan (RTEP) process. AEP's transmission planning activities are carried out as part of and support the RTEP process. Through this planning process, I&M's transmission enhancements are coordinated with the expansion of the transmission system for the entire PJM footprint thereby continuing to ensure a reliable transmission system for meeting I&M's load demand. Also, the Joint Operating

Agreement between PJM and the Midwest Independent System Operator (Midwest ISO) provides for joint transmission planning with Midwest ISO, whose membership includes other utilities in Indiana.

F. Demand Side Management (DSM)[3]

I&M's current and future DSM plans are largely shaped by the Commission's December 9, 2009 Phase II Order in Cause No. 42693 (the "Phase II Order"). This IRP includes energy efficiency programs designed to comply with that order. Also, this IRP validates the cost-effectiveness of energy efficiency and other demand-side programs including emerging smart grid technologies and demand response programs.

In addition to consumer energy efficiency programs, I&M continues to offer a variety of customer tariffs with demand response features, namely, a diverse selection of time-of-day rate options and other conservation-related programs including interruptible tariffs that allow customers to achieve savings through more efficient use of electricity or when the system will benefit from reduced peak demand. I&M evaluates additional tariffs for potential offering to customers on an ongoing basis.

In accordance with the Settlement Agreement approved by the Commission on June 13, 2007 in Cause No. 43231, I&M implemented and completed a smart meter pilot in South Bend, IN as part of its gridSMART® program. The results of the pilot were mixed and as a result, increased or substantial investment in smart meters will be deferred. However, emerging smart grid technologies such as Integrated Volt VaR

[3] Demand Side Management (DSM) refers to utility activities designed primarily to encourage consumers to modify patterns of their electricity usage, including the timing and level of electricity demand. This includes Demand Response (DR) offerings that reduce peak demand (kW) and Energy Efficiency (EE) programs that encourage energy (kWh) conservation.

Control (IVVC) continue to be evaluated.

Reflective of the Company's commitment to sustainability and environmental responsibility, this IRP fully includes the impacts of the Phase II Order, emerging smart grid technologies, and demand response programs in Indiana. Greater detail is provided in Chapters 4 and 10.

G. Major Assumptions

AEP load forecasts specifically account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005 (EPAct 2005), the Energy Independence and Security Act of 2007 (EISA), the Energy Improvement and Extension Act of 2008 (EIEA) and the American Recovery and Reinvestment Act of 2009 (ARRA).

The most dominant issue in the short-term load forecast is the economy. While the national recession has technically ended, the economy has remained sluggish. The expectations are that the economy will continue to expand, but at rates slower than have been experienced historically coming out of a recession. The Company continually monitiors the economy at the national and regional levels. As part of this process, the Company utilizes not only Moody's Analytics, but other public and confidential sources, e.g., the Company has discussions with representatives of its customer's to gauge future electric needs.

I&M, as with any producer of carbon dioxide (CO_2), will be significantly affected by any greenhouse gas (GHG) legislation. For many years, the potential for requirements to reduce greenhouse gas emissions, including CO_2, has been one of the most significant sustainability issues facing I&M and AEP.

EPA is poised to propose first-ever GHG requirements for power plants as early as the end of this year. Given that there are currently no cost-effective post-combustion control technologies available, the standards are anticipated to focus on energy efficiency opportunities, but the substantive requirements of the EPA proposal are not yet known. AEP supports a legislative approach to resolve the GHG issue rather than a regulatory approach. Without this certainty, it is impossible to justify expenditures in the billions of dollars in GHG mitigation strategies that might otherwise put the company and its shareholders at risk. Such legislation appears unlikely in this Congress and diminished somewhat in future Congresses.

For this IRP cycle, the impact of GHG legislation is modeled as a simple carbon dioxide price or tax on solid fuels and as a part of the price of natural gas. This carbon tax is projected to take effect in the 2017-2022 time frame.

In recognition of current and possible future state renewable portfolio standards (RPS), and as a method of reducing GHG emissions, this IRP reflects achievement of state renewable mandates and conformance with voluntary state goals.

The resource plan developed for I&M assumes that I&M and the AEP System-East Zone remain responsible for the generation supply of their retail customers.

H. Cross-Reference Table

The following cross-reference table provides a link between the 170 IAC rule and this plan.

Throughout the plan, specific sections that respond to specific requirements of the rule are highlighted in the subheadings, with the relevant ruling section identified immediately following the subheading. I&M hopes this system will be helpful in linking key plan elements to the rule.

Cross Reference Table

IRP Rule Requirements	Report Reference
170 IAC 4-7-4 Methodology and documentation requirements	
Sec. 4. An IRP covering at least a twenty (20) year future period prepared by a utility must include a discussion of the methods, models, data, assumptions, and definitions used in developing the IRP and the goals and objectives of the plan. The following information must be included:	
(1) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be presented in the form of a reference. The reference must include the source title, author, publishing address, date and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media and hard copy, or as specified by the commission.	Chapter 3.K.- Data Sources, Chapter 12 - Appendix A and Confidential Exhibits 5 and 6
(2) A description of the utility's effort to develop and maintain, by customer class, rate class, SIC code, and end-use, a data base of electricity consumption patterns. The data base may be developed using, but not limited to, the following methods:	Chapter 3.M.- Customer Surveys
(A) Load research developed by the individual utility.	Chapter 3.J. - Historical and Projected Load Profiles and Chapter 3.N - Load Research Class Interval Usage Methodolgy
(B) Load research developed in conjunction with another utility.	Not Applicable
(C) Load research developed by another utility and modified to meet the characteristics of that utility.	Not Applicable
(D) Engineering estimates.	Chapter 3.C.3. - Long-term Forecasting Models
(E) Load data developed by a non-utility source.	Chapter 3.C.3. - Long-term Forecasting Models
(3) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	Chapter 3.M.- Customer Surveys
(4) A discussion of customer self-generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	Chapter 3.O. - Customer Self-Generation
(5) A description of model structure and an evaluation of model performance.	Chapter 3, Sections C, D, & H.; also Conf. Exhibit 5
(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	Chapter 3.G. - Forecast Uncertainty and Range of Forecasts
(7) A description of the fuel inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan.	Chapter 5.C. - Fuel Inventory and Procurement Practices
(8) A description of the SO_2 emission allowance inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan.	Chapter 6 - Environmental Compliance

Cross Reference Table

IRP Rule Requirements	Report Reference
(9) A description of the generation expansion planning criteria used in developing the integrated resource plan. The description must fully explain the basis for the criteria selected, including an analysis and rationale for the level of system wide generation reliability assumed in the IRP.	Chapter 2.D. - Reliability Criteria
(10) A regional, or at a minimum, Indiana specific power flow study prepared by a regional or subregional organization. This requirement may be met by submitting Federal Energy Regulatory Commission (FERC) Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. The power flow study shall include the following:	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(A) Solved real flows.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(B) Solved reactive flows.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(C) Voltages.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(D) Detailed assumptions.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(E) Brief description of the model(s).	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(F) Glossary of terms with cross references to the names of buses and line terminals.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(G) Sensitivity analysis, including, but not limited to, the forecast of the following:	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(i) Summer and winter peak conditions.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(ii) Light Load as well as heavy transfer conditions for one (1), two (2), five (5), and ten (10) years out.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(iii) Branch circuit ratings, including, but not limited to, normal, long term, short term, and emergency.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(11) Any recent dynamic stability study prepared for the utility or by the utility. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(12) Applicable transmission maps. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapter 7.A., Conf. Exhibit 7 and FERC-715 (Conf. Exhibit 4)
(13) A description of reliability criteria for transmission planning as well as the assessment practice used. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(14) An evaluation of the reliability criteria in relation to present performance and the expected performance of the utility's transmission system. The requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapters 7.D., 7.E. and FERC 715 (Conf. Exhibit 4)
(15) A description of the utility's effort to develop and improve the methodology and the data for evaluating a resource (supply-side or demand-side) option's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including transmission, distribution, and generation.	Chapter 7.C., and Chapter 2.D. - Reliability

Cross Reference Table

IRP Rule Requirements	Report Reference
(16) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following:	Chapter 9, also see below.
(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.	Chapter 9.A.
(B) The avoided transmission capacity cost.	Chapter 9.B.
(C) The avoided distribution capacity cost.	Chapter 9.C.
(D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Chapter 9.D.
(17) The hourly system lambda and the actual demand for all hours of the most recent historical year available. For purposes of comparison, a utility must maintain three (3) years of hourly data and the corresponding dispatch logs.	Chapter 12.B. and C.- Appendix
(18) A description of the utility's public participation procedure if the utility conducts a procedure prior to the submission of an IRP to the commission.	Not applicable
170 IAC 4-7-5 Energy and demand forecasts	
Sec. 5. (a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:	Chapter 3, see below and also Chapter 3. Sections C and D
(1) An historical and projected analysis of a variety of load shapes, including, but not limited to, the following:	Chapter 3.J. - Historical and Projected Load Profiles
(A) Annual load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(B) Seasonal load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(C) Monthly load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	Chapter 3.J. - Historical and Projected Load Profiles
(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	Chapter 3.J. - Historical and Projected Load Profiles
(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	Chapter 3.E.- Base Load Forecast Results
(4) The use and reporting of actual and weather normalized energy and demand levels.	Chapter 3.I. - Weather-Normalization of Load
(5) A discussion of all methods and processes used to normalize for weather.	Chapter 3.I. - Weather-Normalization of Load
(6) A twenty (20) year period for energy and demand forecasts.	Chapter 3.E.- Base Load Forecast Results
(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following:	Chapter 3.E.- Base Load Forecast Results

Cross Reference Table

IRP Rule Requirements	Report Reference
(A) Total system.	Chapter 3.E.- Base Load Forecast Results
(B) Customer classes or rate classes, or both.	Chapter 3.E.- Base Load Forecast Results
(C) Firm wholesale power sales.	Chapter 3.E.- Base Load Forecast Results
(8) If an end-use methodology has not been used in forecasting, an explanation as to why this methodology has not been used.	Not Applicable
(9) For purposes of section 5(a)(1) and 5(a)(2) *[subdivisions (1) and (2)],* a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(2) of this rule.	Chapter 3.J. - Historical and Projected Load Profiles and Chapter 3.N.- Load Research Interval Usage Estimation Methodology
Sec. 5. (b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on combinations of alternative assumptions such as:	Chapter 3.G. - Forecast Uncertainty and Range of Forecasts
(1) Rate of change in population.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(2) Economic activity.	Chapter 3.C. and G.
(3) Fuel prices.	Chapter 3.C. and G.
(4) Changes in technology.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(5) Behavioral factors affecting customer consumption.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(6) State and federal energy policies.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(7) State and federal environmental policies.	Not Applicable
170 IAC 4-7-6 Resource assessment	
Sec. 6. (a) For each year of the planning period, excluding subsection 6(a)(6) *[subdivision (6)]*, recognizing the potential effects of self-generation, an electric utility shall provide a description of the utility's electric power resources that must include, at a minimum, the following information:	Chapter 5.C. and Exhibit 5-1
(1) The net dependable generating capacity of the system and each generating unit.	Chapter 5.C. and Exhibit 5-1
(2) The expected changes to existing generating capacity, including, but not limited to, the following:	Chapter 5.C.
(A) Retirements.	Chapter 5.C.
(B) Deratings.	Chapter 5.C.
(C) Plant life extensions.	Chapter 5.C.
(D) Repowering.	Chapter 5.C.
(E) Refurbishment.	Chapter 5.C.
(3) A fuel price forecast by generating unit.	Chapter 5.C. and Conf. Exhibit 1
(4) The significant environmental effects, including:	Chapter 6 and Conf. Exhibit 2
(A) air emissions;	Chapter 6, see also Chapter 6.J. and Conf. Exhibit 2
(B) solid waste disposal;	Chapter 6, see also Chapter 6.B. and Conf. Exhibit 2
(C) hazardous waste; and	Chapter 6, see also Chapter 6.C. and Conf. Exhibit 2
(D) subsequent disposal;	Chapter 6, see also Chapter 6.C. and Conf. Exhibit 2

Cross Reference Table

IRP Rule Requirements	Report Reference
at each existing fossil fueled generating unit.	
(5) The scheduled power import and export transactions, both firm and nonfirm, as well as cogeneration and non-utility production expected to be available for purchase by the utility.	Chapter 5.B.
(6) An analysis of the existing utility transmission system that includes the following:	Chapters 7.C., 7.D., 7.E. and 7.F.
(A) An evaluation of the adequacy to support load growth and long term power purchases and sales.	Chapters 7.D., 7.E. and 7.F.
(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses.	Chapters 7.C., 7.D. and 7.E.
(C) An evaluation of the potential impact of demand-side resources on the transmission network.	Chapters 7.C., 7.D. and 7.E.
(D) An assessment of the transmission component of avoided cost.	Chapters 9.B. and 9.D.
(7) A discussion of demand-side programs, including existing company-sponsored and governmental-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	Chapter 4 - Demand Side Management
Sec. 6. (b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's plan shall, at a minimum, include the following:	Chapter 4 - Demand Side Management
(1) A description of the demand-side program considered.	Chapter 4 - Demand Side Management
(2) A detailed account of utility strategies designed to capture lost opportunities.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(3) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	Chapter 4 - Demand Side Management (discussion) and Chapter 9.A. - Avoided Costs
(4) The customer class or end-use, or both, affected by the program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(5) A participant bill reduction projection and participation incentive to be provided in the program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(6) A projection of the program cost to be borne by the participant.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(7) Estimated energy (kWh) and demand (kW) savings per participant for each program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan

Cross Reference Table

IRP Rule Requirements	Report Reference
(8) The estimated program penetration rate and the basis of the estimate.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(9) The estimated impact of the program on the utility's load, generating capacity, and transmission and distribution requirements.	Chapter 4 - Demand Side Management
Sec. 6. (c) A utility shall consider supply-side resources as an alternative in meeting future electric service requirements. The utility's plan shall include, at a minimum, the following:	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(1) Identify and describe the resource considered, including the following:	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(A) Size (MW).	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(B) Utilized technology and fuel type.	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(C) Additional transmission facilities necessitated by the resource.	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(2) Significant environmental effects, including the following:	Chapter 6, Chapter 5.D. and Exhibit 3 of the Conf. Supplemt
(A) Air emissions.	Chapter 6, Chapter 5.D. and Exhibit 3 of the Conf. Supplemt
(B) Solid waste disposal.	Chapter 6 and Chapter 5.D.
(C) Hazardous waste and subsequent disposal.	Chapter 6 and Chapter 5.D.
(3) An analysis of how a proposed generation facility conforms with the utility-wide plan to comply with the Clean Air Act Amendments of 1990.	Chapter 6 - Environmental Compliance
(4) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Chapter 5.B.
Sec. 6. (d) A utility shall identify transmission and distribution facilities required to meet, in an economical and reliable manner, future electric service requirements. The plan shall, at a minimum, include the following:	Chapters 7.B., 7.C., 7.D., 7.E., 7.F., 7.G. and 7.I.
(1) An analysis of transmission network capability to reliably support the loads and resources placed upon the network.	Chapters 7.D., 7.E. and 7.F.
(2) A list of the principal criteria upon which the design of the transmission network is based. Include an explanation of the principal criteria and their significance in identifying the need for and selecting transmission facilities.	Chapters 7.B. and 7.C.
(3) A description of the timing and types of expansion and alternative options considered.	Chapter 7.G. and 7.I.
(4) The approximate cost of expected expansion and alteration of the transmission network.	Chapter 7.G. and 7.I.
170 IAC 4-7-7 Selection of future resources	
Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through (c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported.	Chapter 5.D.
Sec. 7. (b) Integrated resource planning includes one (1) or more tests used to evaluate the cost-effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e):	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan

Cross Reference Table

IRP Rule Requirements	Report Reference
(1) Participant.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(2) Ratepayer impact measure (RIM).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(3) Utility cost (UC).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(4) Total resource cost (TRC).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(5) Other reasonable tests accepted by the commission.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (d) A utility is required to:	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(1) specify the components of the benefit and the cost for each of the major tests; and	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(2) identify the equation used to express the result.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	Chapter 4 - Demand-Side Management
170 IAC 4-7-8 Resource integration	
Sec. 8. A utility shall select a mix of resources consistent with the objectives of the integrated resource plan. The utility must provide the commission, at a minimum, the following information:	Chapter 8; also see below.
(1) Describe the utility's resource plan.	Chapter 8.E. and 8.F.
(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the least-cost mix of resources.	Chapter 8.B. and 8.C.
(3) Determine the present value revenue requirement of the utility's resource plan, stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.	Chapter 8.H. - Financial Effects
(4) Demonstrate that the utility's resource plan utilizes, to the extent practical, all economical load management, conservation, nonconventional technology relying on renewable resources, cogeneration, and energy efficiency improvements as sources of new supply.	Chapter 5.D.

Cross Reference Table

IRP Rule Requirements	Report Reference
(5) Discuss how the utility's resource plan takes into account the utility's judgment of risks and uncertainties associated with potential environmental and other regulations.	Chapter 6 and Chapter 8.D.
(6) Demonstrate that the most economical source of supply-side resources has been included in the integrated resource plan.	Chapter 8 (mainly 8.C.)
(7) Discuss the utility's evaluation of dispersed generation and targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	Chapter 4.F.
(8) Discuss the financial impact on the utility of acquiring future resources identified in the utility's resource plan. The discussion shall include, where appropriate, the following:	Chapter 8.H. - Financial Effects
(A) The operating and capital costs of the integrated resource plan.	Chapter 8.H. - Financial Effects
(B) The average price per kilowatt-hour as calculated in the resource plan. The price must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.	Chapter 8.H. - Financial Effects and Exhibit 8-12
(C) An estimate of the utility's avoided cost for each year of the plan.	Chapter 9.A.; Exhibit 9-1 and 9-2
(D) The impact of a planned addition to supply-side or demand-side resources on the utility's rate.	Chapter 8.H. - Financial Effects
(E) The utility's ability to finance the acquisition of a required new resource.	Chapter 8.H. - Financial Effects
(9) Identify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP.	Chapter 6 and also throughout the plan as applicable.
(10) Demonstrate, to the extent practicable and reasonable, that the utility's resource plan incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances and preserves the plan's ability to achieve its intended purpose. Unexpected changes include, but are not limited to, the following:	See below.
(A) The demand for electric service.	Chapter 8.D.
(B) The cost of a new supply-side or demand-side technology.	Chapter 8.D. and 8.D.2.
(C) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Chapter 8.D.
170 IAC 4-7-9 Short term action plan	
Sec. 9. A short term action plan shall be prepared as part of the utility's IRP filing or separately, and shall cover each of the two (2) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the resource options or programs contained in the utility's current integrated resource plan where the utility must take action or incur expenses during the two (2) year period. The short term action plan must include, but is not limited to, the following:	Chapter 10 - Short-Term Action Plan
(1) A description of each resource option or program included in the short term action plan. The description must include, but is not limited to, the following:	Chapter 10 - Short-Term Action Plan
(A) The objective of the resource option or program.	Chapter 10 - Short-Term Action Plan

Cross Reference Table

IRP Rule Requirements	Report Reference
(B) The criteria for measuring progress toward the objective.	Chapter 10 - Short-Term Action Plan
(C) The actual progress toward the objective to date.	Chapter 10 - Short-Term Action Plan
(2) The participation of small business in the implementation of a DSM resource option or program.	Chapter 10 - Short-Term Action Plan
(3) The implementation schedule for the resource option or program.	Chapter 10 - Short-Term Action Plan
(4) The timetable for implementation and resource acquisition.	Chapter 10 - Short-Term Action Plan
(5) A detailed budget for the cost to be incurred for each resource or program.	Chapter 10 - Short-Term Action Plan

2) OBJECTIVES AND PROCESS

2. Objectives and Process

A. Introduction

The AEP Service Corporation provides management, technical, and financial services to the operating companies. I&M's parent company, American Electric Power (AEP), serves a population of about 7.2 million customers (3.2 million retail customers) in a 41,000 square-mile area in parts of Arkansas, Indiana, Kentucky Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP is based in Columbus, Ohio. In 2010 the residential, commercial, and industrial customers accounted for 30.7%, 23.2%, and 33.0%, respectively, of AEP-East total internal energy requirements of 125,381 GWh. The remaining 13.1% was supplied for use in the public street and highway lighting, sales-for-resale, and all other categories.

I&M is one of five operating companies of the AEP System-East Zone for which generation assets are currently planned and operated on an integrated basis under the FERC-approved AEP Interconnection Agreement ("IA," "Interconnection Agreement" or "AEP Pool".) AEP has seven East Zone operating companies, but two do not include generation resources. This Interconnection Agreement provides for mutual assistance during emergencies, maximum dependability in the day-to-day production of the electric power requirements of all AEP customers, and maximum economies of scale. The AEP System-West Zone includes portions of Texas, Louisiana, Oklahoma and Arkansas.

On December 17, 2010, pursuant to Article 13 of the Interconnection Agreement, each of the AEP Pool members gave written notice to the other members, and to American Electric Power Service Corporation ("AEPSC"), the AEP Pool's agent, of its intent to modify the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC[4]. Because the IA is a rate schedule on file at FERC, its modification will not be effective until accepted for filing by FERC.

The Interim Allowance Agreement among the AEP companies ("IAA"), which was most recently modified in 1996 and deals with sulfur dioxide (SO_2) emissions and allowances, would be terminated. Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_X). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions.

By giving notice to modify, and possibly terminate, the IA and terminate the IAA, the AEP Pool members are providing a framework and timeline within which all interested stakeholders have an opportunity to participate in the determination of how the AEP-East operating companies should operate prospectively. This process has already begun in several states, for example I&M has engaged with several stakeholders in Indiana and Michigan. Other AEP Pool members have made similar contacts with stakeholders in their respective state jurisdictions.

Assuming this AEP Pool modification/termination notice is not revoked or significantly modified, by 2014, I&M's resource planning relationship with the other AEP-East companies could take one of a number of plausible forms. Rather than plan for every potential outcome, which would not be particularly efficient or beneficial, I&M has

[4] The timing of the modification or termination of the IA may be affected by the Stipulation pending before the Public Utilities Commission of Ohio in (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO), which, if approved, would require the generating assets in Ohio to be placed in a separate corporation and result in the filing at the FERC to be made in early 2012.

analyzed two potential conditions. First, an integrated resource plan (IRP or "Plan") for I&M as a stand-alone entity beginning in 2014 has been created. A second plan with I&M as part of the AEP-East Pool in its existing construct has also been considered, however, the AEP Pool plan yields the same resource additions for I&M as the No AEP Pool plan.

This IRP document neither pre-supposes the AEP Pool/Stand-Alone end-state, nor does it make any recommendation regarding AEP-East company relationships in a "post-AEP Pool" world. Rather, it merely presents a plan for I&M to meet its obligations under the two potential governance scenarios outlined above.

This IRP is being presented at a time of great uncertainty with regard to the future status of I&M's relationship to the other AEP-East generating companies. The AEP Pool construct, which has been in place since 1951 (with modifications over time) will likely be modified by 2014. The final outcome of pending environmental regulations may require a significant level of capacity retirements in a relatively short period of time. Over the next three to six months, proposed environmental rules will be finalized and AEP Pool negotiations will be underway, and that may provide a higher level of certainty with regard to actions the Company should embrace. Until that certainty is realized, the Company's plan is to maintain optionality and flexibility in meeting the requirements of its customers.

Therefore, in this Plan, future market purchases (for AEP-East) over this 20-year forecast period ideally represent initial "placeholders" for such incremental capacity resource needs. It is the Company's intent to continually investigate and analyze the economic merits of future opportunities to build (or acquire) "owned-resources" in lieu of such purchases to ensure greater (local) electrical reliability and price certainty for its customers. However, it should be considered that in the PJM region, most load serving entities (LSE) receive capacity through the market construct known as the Reliability Pricing Model (RPM) auction process. So while the concept of relying on the market may not be the approach chosen by the AEP-East operating companies, it is an accepted practice for many utilities in the region.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. In light of the current economic conditions and the movement towards the increased use of renewable generation and end-use efficiency, as well as known and proposed environmental rulemaking to further control fossil plant emissions which will likely result in the retirement, conversion or retrofit of existing generating units, supply of capacity and energy to I&M will continue to be impacted. The resource planning process is becoming increasingly complex given such pending legislative and regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and energy efficiency advancements all of which necessitate flexibility in any ongoing planning activity and processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on I&M customers will be a primary consideration in this report.

Exhibit 8-10 and Exhibit 8-11 show that both I&M and AEP-East, under their recommended plans, are anticipated to meet their reserve margin requirements over the forecast period.

B. Objectives

The purpose of this report is to present I&M's IRP process and the resulting plan. The resulting plan (The Plan) is intended to provide the lowest reasonable cost of power to I&M's customers while meeting environmental and reliability constraints. The Plan should be both flexible and robust, so the need to make changes is minimized.

C. Assumptions

1. Environmental

This IRP considers final and proposed future United States Environmental Protection Agency (EPA) regulations, as described in Chapter 6, which will impact fossil-fueled electric generating units (EGU).

The EPA has issued final rulemaking to replace the former Clean Air Interstate Rule (CAIR) for the regulation of SO_2 and NO_X which had previously been remanded by the federal courts. The EPA issued the CSAPR to establish state-specific emission budgets for SO_2 and both annual and seasonal (May-September) NO_X with a two-phase emission reduction beginning in 2012. Further, the federal EPA proposed the EGU Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the court vacated Clean Air Mercury Rule (CAMR). EGU MACT will regulate emissions of hazardous air pollutants (HAPs) such as mercury, arsenic, chromium, nickel, certain acid gases and organic HAP compounds and is expected to be finalized in November 2011 with full implementation in 2015. The EPA is also expected to propose first-ever requirements regulating GHG emissions later this year, but the substance of those requirements is not known. Combined, the CSAPR, MACT rule, and other impending federal air regulatory programs will require significant emission reductions from all U.S. coal and lignite-fired units. Emission reductions will be achieved beginning in 2012 as a result of unit retirements, unit curtailments, and installation of emission control technologies, including flue gas desulphurization (FGD) or dry sorbent injection (DSI), selective catalytic reduction (SCR), activated carbon injection (ACI), and fabric filter systems. In the AEP-East states, these new and proposed emission reduction programs will accelerate planned environmental retrofit projects and will drive unit curtailments beginning in 2012.

In addition, a new rule on the handling and disposal of coal combustion residuals (CCR) is being developed by the EPA, which, as proposed, would require significant additional capital investment in the coal-fired EGU to convert "wet" ash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to "dry" systems and in addition build waste-water treatment facilities to process plant groundwater run-off before discharge. The EPA is developing regulations with respect to the intake of cooling water and discharge of wastewater, which also has the potential to require significant capital investment for compliance.

The cumulative cost of complying with these final and proposed environmental rules will be highly burdensome to I&M, the AEP-East operating companies, and their customers. Such requirements will also accelerate proposed retirement dates of any currently non-retrofitted coal unit in the AEP-East fleet as established within this 2011 IRP, as discussed in Chapter 5.

2. Customer Base

This report assumes that both the I&M and AEP System-East Zone customer bases remain relatively stable, for the duration of the planning period.

3. "Market vs. Build" Considerations

In addition to the fundamental capacity pricing information in the modeling (discussed below), available information suggests that capacity reserve margins–inclusive of current and anticipated merchant capacity–will decline to the point that new assets will have to be built within the next decade in the PJM area that includes the AEP System-East Zone.

The need for new capacity will increase as the impact from final and proposed EPA legislation, as mentioned in Chapter 6, is experienced and accelerated unit retirements occur as a result.

D. Reliability Criteria (170 IAC 4-7-4(9), & 4(15))

On October 1, 2004, the AEP System-East Zone transferred functional control of its transmission facilities as well as generation dispatch including the transmission and generation facilities owned by I&M, to PJM (the Commission approved this action by order dated September 10, 2003 in consolidated Cause Nos. 42350 and 42352). With that, the PJM Reliability Assurance Agreement defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity (LSE) in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's Installed Reserve Margin (IRM) requirement. This requirement is itself based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, load diversity between each LSE and PJM as a whole and generating asset equivalent forced outage rates represent other factors impacting the LSEs' required minimum reserve levels.

The PJM RTO determines generation planning reserve requirements using probabilistic methods and a target loss of load criterion of one day in ten years. The method is similar to that historically used by I&M. PJM determines an installed capacity margin that has to be met by each of its members. This is converted into PJM Unforced Capacity (UCAP) requirements. However, for ease of understanding, the requirement is expressed in this report in terms of installed capacity.

A required PJM IRM of 15.3% was used as the starting point for the plan. However, the AEP System-East Zone's actual reserve margin requirement is closer to 12%. This stems from the diversity between the AEP System-East Zone peak and the PJM RTO peak. Historically, the AEP System-East Zone has experienced about 3% diversity against PJM peaks and as a result the AEP System-East Zone's capacity obligation is roughly 3% lower, when described in terms of the zonal peak, than it would be if described in terms of the peak coincident with PJM.

Although the current plan contains a changing mix of capacity through time, it also contains uncertainty surrounding the long-term forecast. As a result, the AEP System-East Zone IRM has held steady at 15.3% for the remainder of the forecast period. However, it is important to note that PJM can revise the IRM annually as required, and as a result AEPSC will adjust the future IRM estimates accordingly.

In February 2007, AEPSC, as agent for the AEP System-East Zone LSEs, gave formal notice of its intent to opt-out of the initial PJM "Reliability Pricing Model" (RPM) capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized "Fixed Resource Requirement" (FRR) construct. FRR requires AEP to set forth its future AEP System -East Zone capacity resource plan under, essentially, a "self-planning" format. This is an approach that would, however, initially not give AEP access to those generating sources offered into the PJM capacity auction, but rather would allow AEP to be free to plan for and build (or buy) the required generating capacity that would best fit the needs of its customers - such capacity purchases being limited by rule to either non-PJM generation sources, or PJM generation sources not cleared/picked-up within the RPM auction process.

AEP has opted out of the RPM capacity auction through the 2014/15 delivery year, for which the auction was held in May 2011 and will determine for each subsequent year whether to continue to utilize FRR for an additional year or to opt-in to the RPM auction for a minimum five-year period.

E. Planning Process

The resource planning process includes the following basic steps:

1. *Load Forecasting (Energy and Demand)* — Development of energy and peak demand *pro forma* estimates for customers for which I&M has–or anticipates– a known regulatory obligation to serve, as well as an estimation of wholesale customer load and demand profiles intended to optimize available generation.

2. *Reliability Analysis / Reserve Criteria* — Consideration of RTO and/or zonal requirements concerning sufficiency of (long-term) capacity planning reserves.

3. *Review / Assessment of Current Resources* — Broadly construed, this involves consideration of any physical or economic factor – including environmental compliance

requirements – that may affect future use of current generation.

4. *Determination of Adequacy of Current Resources / Need for Additional Resources* — Matching existing and currently planned resources against total requirements (load plus reserve requirements), to determine projected shortfalls / needs.

5. *Identification of Capacity Resource Options* — Consideration of various resource options: supply-side and demand-side resources including self-build; market purchase; asset purchases; available technology options; demand response tariffs; energy efficiency programs; etc.

6. *Determination of Optimal Resource Mix and Timing* — Consideration of the timing and optimal resource mix for new supply and demand resources within the planning period under various modeling assumptions.

7. *Implementation Considerations* — Consideration of corporate ability to implement the plan, as well as siting and other practical considerations.

Given the diverse and far-reaching nature of the many elements and participants in this process, it is imperative to emphasize that this is a continuously evolving activity.

In general, assumptions and plans are continually reviewed and modified as new information becomes available, and therefore are subject to change. Such analysis is needed to ensure that changing markets, market structures, technical parameters, reliability and environmental requirements are constantly re-assessed to balance the interests of all stakeholders: customers, regulators, and shareholders.

1. Planning Organization

This report presents results based on input received from many functional areas coordinated by AEPSC Corporate Planning & Budgeting (CP&B) Department. The areas individually investigated were:

- *Existing Unit Disposition* – examination of the physical and financial attributes and focused evaluations surrounding potential disposition options for certain existing generating units.
- *New Generation/Technology Review* – assessment of generation technologies considered for modeling, including renewables; as well as optimal unit siting and technology options.
- *Capacity, Load/Demand, Reserves* – determination of load and demand profiles (retail and wholesale) to be modeled, existing unit capability modifications needed, as well as zonal (capacity) reliability requirements; and initial "baseline" planning reserve margin profiles.
- *Transmission Integration Review* – review of physical transmission constraints relating to current power and energy import/export capabilities that would impact the IRP, as well as a review of the associated relative transmission infrastructure impacts and costs.
- *Demand Side Management* – evaluations of potential cost-effective Demand Side Management (DSM) programs.
- *Renewable Resource Evaluation* – evaluations of potential cost-effective Renewable Resource programs that will aid in the achievement of state-mandated or voluntary renewable energy targets.
- *Resource Planning (RP) Modeling* – modeling of the least-cost "type and timing" of capacity resources to meet reliability and environmental compliance requirements at or near the lowest reasonable cost.
- *Finance and Regulatory Planning Modeling* – modeling of the corporate financial impacts of the IRP strategy in conjunction with other anticipated financial requirements.

3)ENERGY AND DEMAND FORECAST

3. Energy and Demand Forecast

A. Summary of Load Forecast

1. Forecast Assumptions

The I&M load forecast in this report is based on an economic outlook issued in October 2010 by Moody's Analytics. The forecast is based on load experience prior to 2011. Moody's Analytics projects moderate growth in the U.S. economy during the 2011-2031 forecast period, characterized by moderate inflation and a 2.4% average annual rise in real Gross Domestic Product (GDP), with the consumer price index expected to rise by 2.2% per year. Industrial output, as measured by the Federal Reserve Board's index of industrial production, is projected to grow at 1.1% per year during the same period. Moody's Analytics also created the regional economic forecasts. The outlook for I&M's Indiana service area projects employment growth of 0.4% per year during 2011-2031, with real regional income per-capita growth of 1.5%.

Inherent in the load forecasts are the impacts of past customer energy conservation activities, including company-sponsored DSM programs already implemented. The load impacts of future or expanded DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts, as discussed in Chapter 4 of this report.

The load forecast does incorporate end-use concepts in its residential and commercial forecasts, which enables the evaluation of energy efficiency standards and other energy conservation trends.

2. Forecast Highlights

I&M's total internal energy requirements are forecasted to increase at an average annual rate of 0.3% from 2012 to 2031, this is slightly lower than the 0.4% forecasted for the AEP System-East Zone as a whole. For the Indiana portion of the Company's service area, the annual growth rate is expected to be 0.2%. I&M's corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.4% and 0.2%, respectively, with annual peak demand expected to continue to occur in the summer season through 2031.

B. Overview of Load Forecasting Methodology

I&M's load forecasts are based mostly on econometric, supplemented with state-of-the-art statistically adjusted end-use, analyses of time-series data – producing an internally consistent forecast. This consistency is enhanced by model logic expressed in mathematical terms and quantifiable forecast assumptions. This is helpful when analyzing future scenarios and developing confidence bands. Additionally, econometric analysis lends itself to objective model verification by using standard statistical criteria. This is particularly helpful because it allows apples-to-apples comparisons of different companies and forecast periods.

In practice, econometric analysis highlights alternatives in forecasting models that may not be immediately obvious to the layperson. Likewise, professional judgment is required to interpret statistical criteria that are not always clear-cut. I&M's analysts strive to interpret this data to produce as useful and as accurate a forecast as possible.

In pursuit of that goal, I&M's energy requirements forecast is derived from two sets of econometric models: 1) a set of monthly short-term models and 2) a set of long-term models, with some using monthly data and others using annual data. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves.

- For the first full year of the forecast, the forecast values are generally governed by the short-term models, using billed or metered energy sales. The long-term sales are determined by the long-term models using billed sales.
- The short- and long-term forecasts are usually blended during the first six months of the second full year of the forecast. The blending ensures a smooth transition from the short-term to the long-term forecast.

For those long-term forecasts that are quarterly, a monthly load shape is applied to the forecast based on analysis from the short-term models. The blended sales forecasts are converted to billed and accrued energy sales, which are consistent with the energy generated.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic conditions and demographics, energy prices, weather factors, special information such as known plans of specific major customers, and informed judgment are all used in producing the forecasts. The major difference between the two is that the short-term models use mostly trend, seasonal, and weather variables, while the long-term models use structural variables, such as population, income, employment, energy prices, and weather factors, as well as trends. Supporting forecasting models are used to predict some inputs to the long-term energy models. For example, natural gas models are used to predict sectoral natural gas prices that then serve as inputs.

Either directly, through national economic inputs to the forecast models, or indirectly, through inputs from supporting models, I&M's load forecasts are influenced by the outlook for the national economy. For the load forecasts reported herein, Moody's Analytics' October 2010 forecast was used as the basis for that outlook. Moody's Analytics' regional forecast, which is consistent with its national economic forecast, was used for the regional economic forecast of income, employment, households, output, and population.

Company energy efficiency and demand side management program goals are included in the load forecast. The incremental impacts discussed in section 4, Demand Side Management. The impacts are subtracted from the blended sales forecast by revenue class.

The energy forecast for the AEP System–East Zone, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP System–East Zone operating companies. The same method is used to determine the forecast of peak internal demand and adjusting for diversity.

The demand forecast model is a series of algorithms for allocating the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information. Flow charts depicting the structure of the models used in projecting electric load requirements are shown in Exhibits 3-1 and 3-2. Page 1 of Exhibit 3-1 depicts the development stages of all internal energy requirements forecasts. Pages 2 through 9 of Exhibit 3-1 provide the stages of the Statistically Adjusted End-Use Models for the residential and commercial sectors. Exhibit 3-2 presents a schematic of the peak demand and internal energy requirements forecasting process. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix and in Exhibits 5 and 6 of the Confidential Supplement. Due to the voluminous nature of the model outputs, only model results for energy sales in the Indiana service area and peak demand for the Company are provided.

C. Forecasting Methodology For Internal Energy Requirements (170 IAC 4-7-4(5) and 170 IAC 4-7-5(a))

1. General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of Indiana energy consumption, by customer class. For the purposes of the load forecast, the short term is defined as the first one to two years, and the long term as the years beyond the short term.

Conceptually, the difference between short and long term energy consumption relates to changes in the stock of electricity-using equipment, rather than the passage of time. The short term covers the period during which changes are minimal, and the long term covers the period during which changes can be significant. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology determine the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to impact them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2. Short-term Forecasting Models

The goal of I&M's short-term forecasting models is to produce an accurate load forecast for the first full year. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating and cooling degree-days. The heating and cooling degree-days are measured at weather stations in the service area. The forecasts relied on autoregressive integrated moving average (ARIMA) models.

The estimation period for the short-term models was January 2000 through October 2010.

a. Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

b. Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 10 large industrial customers in Indiana and for the remainder of industrial energy customers as a unit. These 11 short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 10 large industrial customers and the forecast for the remainder of the industrial customers.

c. All Other Energy Sales

The "all other" energy sales category includes public street and highway lighting, municipals, cooperative (Wabash Valley Power Association) and the Indiana Municipal Power Association (IMPA). The Indiana municipal customers reflected in the forecast include Auburn, Avilla, Bluffton, Garrett, Mishawaka, New Carlisle and Warren. Auburn is forecasted separately and the remainder of the municipals are forecasted in aggregate.

Both the other retail and municipal models are estimated using ARIMA models. I&M's short-term forecasting model for public street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale models include binaries, heating and cooling degree- days, lagged error terms and lagged energy sales.

3. Long-term Forecasting Models
(170 IAC 4-7-4(2) (D) and (E), and 170 IAC 4-7-5(b) (1) through (6))

The goal of the long-term forecasting models is to produce a reasonable load outlook. Given that goal, the long-term forecasting models, which were separately estimated for the Indiana and Michigan service areas, employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the I&M service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price, which can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The estimation period for the long-term load forecasting models was 1984-2010. The long-term energy sales forecast is developed by blending the second full year of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

a. Natural Gas Price Forecast

In order to produce forecasts of certain independent variables used in the long-term internal energy requirements forecasting models, a supporting forecast was developed, i.e., a natural gas price forecast for the Company's service area.

The forecast price of natural gas used in I&M's energy models comes from a forecast of state natural gas prices for four primary consuming sectors: residential, commercial, industrial and electric utilities. The forecast of sectoral prices was assumed to have the same growth as the U.S. sectoral prices. The U.S. natural gas price forecasts were obtained from U.S. DOE/EIA's *2010 Annual Energy Outlook.*

b. Residential Energy Sales

Residential energy sales are forecasted using two models, the first of which projects the number of residential customers and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer count and usage forecasts.

c. Residential Customer Forecasts

The long-term residential customer forecasting model is linear and monthly. The model for the Indiana service area is depicted as follows:

$$customers = f(grossregionalproductpercapita, mortgagerate, customers_{-1})$$

The mortgage interest rate provides a measure for household formation, while service area real gross regional product per capita provides a measure of economic growth in the region, which will also affect customer growth. The lagged dependent variable captures the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The customer forecast is blended with the short-term residential customer forecast to produce a final forecast.

d. Residential Energy Usage Per Customer

The residential usage model is estimated using a Statistically Adjusted End-Use Model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation like the following:

$$Use = f(Xheat, Xcool, Xother)$$

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree- days, household size, personal income, gas prices, and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income, gas prices, and electricity prices.

The appliance saturations are based on historical trends from I&M's residential customer survey. The saturation forecasts are based on DOE forecasts and analysis by Itron. The efficiency trends are based on U.S. Department of Energy (DOE) forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE model is estimated using a linear regression model. It is a monthly model for the period January 1990 through September 2010. This model incorporates the effects of the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (EISA), American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA) on the residential energy.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

e. Commercial Energy Sales

Long-term commercial energy sales are forecast using a SAE model. This model is similar to the residential SAE model. The functional model is as follows:

$$Energy = f(Xheat, Xcool, Xother)$$

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from DOE's *2010 Annual Energy Outlook*. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product from Moody's Analytics. The equipment stock and square footage information are for the East North Central Census Region.

The SAE is a linear regression for the period January 1996 through September 2010. As with the residential SAE model, the effects of the EPAct, EISA, ARRA and EIEA are captured in this model.

f. Industrial Energy Sales

Industrial energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(electricityprice, grpmanufacturing, employment)$$

Service area employment and the service area gross regional product for manufacturing are used as measures of manufacturing activity in the region. Real electricity price for industrial customers is used as I&M's own price measure. In addition binary variables are used for special occurrences.

g. All Other Energy Sales

The all other energy sales category is comprised of public street and highway lighting (PSHL) and sales-for-resale.

The PSHL forecast is a quarterly model driven by regional commercial employment, which is a measure of economic expansion in the region and the need for additional lighting.

The wholesale customers forecast is the same as for the short run models. These models are monthly and have the follow structure:

$$energy = f(employment, population, output, price, heating, cooling)$$

Each model is driven by the Company's Indiana service area employment, population or gross regional product, which are used as measures of economic growth in the region. Average real electric price for I&M Indiana wholesale customers is use to estimate the effects of price on sales. Heating and cooling degree-days are used to capture the sensitivity to weather of the energy sales.

4. Blending Short-term and Long-term Forecast Results

Forecast values for 2011 are generally taken from the short-term process. Forecast values for 2012 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2012 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results.

5. Billed/Unbilled and Losses

a. Billed/Unbilled Analysis

Unbilled energy sales are forecast using the same methodology that is used by the Company to compute actual unbilled sales each month as part of its closing process. The Company starts with the projected monthly internal energy requirements forecast, subtracts the forecasted billed sales and estimate for line losses to derive the forecasted net unbilled sales.

b. Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, loss study results are incorporated to apply losses to each revenue class.

D. Forecasting Methodology for Seasonal Peak Internal Demand (170 IAC 4-7-4(5) and 4-7-5 (a))

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Iron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total for AEP companies in a RTO or total AEP System. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

E. Base Load Forecast Results (170 IAC 4-7-5(a) (3) and (6) and (7) (A-C))

Exhibit 3-3 presents I&M's annual internal energy requirements forecasted for the years 2011-2031, and on actual requirements from the years 2001-2011 (with 2011 being part history and part forecast). The requirements are separated by major category (residential commercial, industrial and other internal sales, as well as system losses). The exhibit also shows the average annual growth rates for both the historical and forecast periods. Exhibits 3-4 and 3-5 present the corresponding information for I&M's Indiana and Michigan service areas, respectively. Also, Exhibit 3-6 provides a disaggregation of the forecasted "other internal sales" figures shown on Exhibits 3-3 to 3-5.

For the AEP System–East Zone, information on actual and forecasted annual internal energy requirements is given on Exhibit 3-7.

Exhibits 3-8 and 3-9 show, for I&M and the AEP System–East Zone, respectively, actual and forecasted summer, winter and annual peak demands, along with annual total internal energy requirements. Also shown are the associated growth rates and annual load factors. The forecasts provided in Exhibits 3-3 through 3-9 reflect after the effects of filed demand-side management programs.

F. Impact of Conservation and Demand-Side Management

The impact of past and ongoing customer conservation and load management activities, including DSM programs, is embedded in the historical record of electricity use and, in that sense, is intrinsically reflected in the load forecast. The load impacts of potential expanded DSM installations are analyzed separately and subtracted from the blended sales forecast. That analysis will be provided in Chapter 4 of this report.

G. Forecast Uncertainty and Range of Forecasts (170 IAC 4-7-4(6) and 170 IAC 4-7-5(b) (2) and (b) (3))

Even though load forecasts are created individually for each of the operating companies in the AEP System–East Zone, and aggregated to form the AEP System–East Zone total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP System–East Zone load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals with a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving-force variables. I&M continues to support both approaches. However, this report uses scenarios for capacity planning sensitivity analyses.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System–East Zone internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the load forecasts for all operating companies. The mini-model is intended to represent the full forecasting structure employed in producing the base-case forecast for the AEP System–East Zone and, by association, for the Company. The dependent variable is total AEP System–East Zone internal energy requirements, excluding sales to the two aluminum reduction plants in the AEP System–East Zone service area. This aluminum load is a large and volatile component of total load, which is treated judgmentally, not analytically, in the load forecast. It is simply added back to the alternative forecasts produced by the mini-model to create low- and high-case scenarios for total internal energy requirements. The independent variables are real service area gross regional product (GRP), AEP System–East Zone service-area employment, the average real price of electricity to all AEP System–East Zone customer classes, the average real price of natural gas in the seven states served by AEP System–East Zone, and AEP System–East Zone service-area heating and cooling degree-days. All variables are expressed in logarithms. Acceptance of this particular specification was based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticity's derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the base load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflected professional judgment. The low- and high-case growth rates in real GRP for the forecast period were 0.9% and 2.2% per year, respectively, compared to 1.6% for the base case. The low- and high-case growth rates for AEP-East Zone region total employment were 0.1% and 0.9% per year, respectively, compared to 0.5% per year for the base case. For the real price of natural gas, the low case assumed a growth rate of 1.6% per year, and the high case assumed a growth rate of 0.9% per year. These compare to a base-case growth rate of 1.2% for the average real gas price in the seven states served in the AEP System–East Zone. Real electricity price high and low cases assumed average annual growth rates of 1.0% and 0.5%, respectively. Meanwhile, the base case for real electricity price assumed an average annual growth of 0.8%. Variations in weather were not considered; so the value of heating and cooling degree-days remained the same in all cases.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for the AEP System–East Zone and I&M are tabulated in Exhibits 3-10 and 3-11, respectively. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for the AEP System–East Zone and I&M are shown in Exhibits 3-12 and 3-13.

For AEP System–East Zone, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2031, represent deviations of about 7% below and 7% above, respectively, the base-case forecast (with the corresponding I&M forecast showing about the same percentage deviation). In this regard, the low-case and high-case growth rates in summer peak internal demand for the forecast period were 0.1% and 0.7% per year, respectively, compared to 0.4% per year for the base case.

H. Performance of Past Load Forecasts (170 IAC 4-7-4(5))

These exhibits reflect the uncertainty inherent in the forecasting process, and demonstrate the changing perceptions of the future.

The performance of the Company's past load forecasts is reflected in Exhibit 3-14, which displays, in graphical form, annual internal energy requirements and summer peak demands experienced since 1990, along with the corresponding forecasts made in 2001, 2003, 2005, 2007, 2009 and 2011 (the current forecast). Exhibit 3-15 presents the same information for the AEP System–East Zone.

I. Weather-Normalization of Load (170 IAC 4-7-5(a) (4) and (5))

Exhibit 3-16 compares the recorded (i.e., actual) and weather-normalized summer and winter peak internal demands and annual internal energy requirements for both I&M and the AEP System-East Zone, respectively, for the last ten years, 2001-2010.

Peak normalization is a fundamental process of evaluating annual or monthly peaks over time, without the impact of "abnormal" weather events and load curtailment events. The limited number of true annual or monthly peaks over time makes it difficult to use traditional regression analysis. So, a regression model is used to determine statistical relationships among a set of daily observations that are similar to annual/monthly peaks and weather conditions. Any load curtailment or significant outage events are added back to the daily observations. The peak normalization demand model is replicated numerous times in a Monte Carlo (stochastic) simulation model. This approach derives probability distributions for both the dependent variable (peak) and independent variables (weather). Multiple estimates for peak are obtained over time, that ultimately produce a weather normalized peak.

Similarly, for each year, the weather-normalized internal energy requirements were determined by applying, to each month of the year, an adjustment related to heating or cooling degree-days, as appropriate, to each sector of the recorded internal energy requirements. The adjustment for each sector was obtained as the product of (1) the difference between the service area's expected (or "normal") heating or cooling-degree-days for the month and the actual heating or cooling degree-days for that month and (2) a weather-sensitivity factor (in MWh per heating or cooling degree-day), which was estimated by regressing over the past years monthly sectoral energy requirements against heating or cooling degree-days for the month. The normalized monthly energy requirements thus determined for each sector were then added for all sectors across all twelve months to obtain the net total weather-normalized energy requirements for the year.

J. Historical and Projected Load Profiles
(170 IAC 4-7-4(2) (A), 170 IAC 4-7-5(a) (1) (A), (B), (C) and (D), 170 IAC 4-7-5(a) (2) and (9))

Exhibits 3-17 to 3-21 display various historical and forecasted load profiles pertinent to the planning process. Exhibit 3-17 shows profiles of monthly peak internal demands for the AEP System–East Zone and I&M on an actual basis for the years 2001 and 2006, and as forecasted for 2011 (includes actual data through August), 2021 and 2031. Exhibit 3-18 shows, for the winter-peak month and summer-peak month for the years 2005 and 2010, respectively, the AEP System's–East Zone average daily internal load shape for each day of the week, along with the peak-day load shape. Exhibit 3-19 shows the corresponding daily internal load shapes for I&M.

Exhibit 3-20 displays, for the forecast years 2011 and 2021, AEP System's–East Zone daily internal load shapes for a simulated week in the winter-peak month (January) and summer-peak month (August). In both cases, a weekday is assumed to represent the day of the monthly (and seasonal) peak. Such load shapes were developed for use in integrated resource planning analyses. The corresponding profiles for I&M are displayed in Exhibit 3-21.

AEP maintains an on-going load research program consisting of samples of each major rate class in each jurisdiction. Exhibit 3-22 displays I&M's Indiana jurisdiction residential, commercial and industrial customer class summer and winter 2010 load shape information derived from these samples.

K. Data Sources (170 IAC 4-7-4 (1))

The data used in developing the I&M load forecast come from both internal and external sources.

The external sources are varied and include state and federal agencies, as well as Moody's Analytics. Exhibit 3-23 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecast.

L. Changes in Forecasting Methodology

Opportunities to enhance forecasting methods are explored by I&M/AEP on a continuing basis. The forecasts reported herein reflect a limited number of changes in the methodology implemented during the last two years.

M. Load-Related Customer Surveys (170 IAC 4-7-4(2) and 170 IAC 4-7-4(3))

A residential customer survey was last conducted in the winter of 2010 in which data on end-use appliance penetration and end-use saturation rates were obtained. Beginning in 1980, in intervals of approximately three years, the Company has regularly surveyed residential customers to monitor customers' demographic characteristics, appliance ownership, penetration of new energy use products and services, and conservation efforts.

The Company has no proposed schedule for industrial and/or commercial customer surveys to obtain end-use information in the near future. I&M monitors its industrial and commercial (and residential) customer end-use consumption patterns through its ongoing load research program.

N. Load Research Class Interval Usage Estimation Methodology (170 IAC 4-7-4(2)(A) and 170 IAC 4-7-5(9))

This section describes the methodology used to estimate load usage by customer class.

AEP is a participating member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee, was a significant contributor to the AEIC

Load Research Manual, and uses the procedures set forth in that manual as a guide for load research practices. AEP maintains an on-going load research program in each retail rate jurisdiction which enables class hourly usage estimates to be derived from actually metered period data for each rate class for each hour of each day. The use of actual period metered data results in the effective capture of weather events and economic factors in the representation of historical usage.

For each rate class in which customer maximum demand is normally less than 1 MW, a statistical random sample is designed and selected to provide at least 10% precision at the 90% confidence level at times of company monthly peak demand. In the sample design process, billing usage for each customer in the class is utilized in conjunction with any available class interval data to determine the optimal stratified sample design using the Dalenius-Hodges stratification procedure. Neyman Allocation is used to determine the necessary number of sample customers in each stratum. All active customers with the requisite data available in the rate class population are included in the sample selection process, which uses a random systematic process to select primary sample points and backup sample points for each primary point.

For selected sample sites that reside within an AMI area, the interval data is extracted from the Meter Data Management System and imported into the ITRON MV90 System. For selected sample sites that reside outside of an AMI area, each location undergoes field review and subsequent installation of an interval data recorder. The recorder is normally set to record usage in fifteen minute intervals. For rate classes in which customer maximum demand is normally 1 MW or greater, each customer in the class is interval metered, and these are referred to as 100% sampled classes. The interval data is retrieved at least monthly, validated through use of the ITRON MV90 System, edited or estimated as necessary, and stored for analytical purposes. The status of each sample point undergoes on-going review and backup sample points replace primary sample points as facilities close, change significant parameters such as rate class, or become unable to provide required information due to safety considerations. This on-going sample maintenance process ensures reasonable sample results are continuously available, and samples are periodically refreshed through a completely new sample design and selection process to capture new building stock and when necessary to capture rate class structure changes.

Prior to analysis, as an additional verification that all interval data is correct, interval data for each customer is summed on a billing month basis and the resulting total energy and maximum demand are compared to billing quantities. Any significant discrepancies between the interval data and the billing quantities are further investigated and corrected, as needed. Rate class analysis is then performed through the MV90 Load Research Package. This industry accepted program combines the individual customer hourly data for each sample point in each stratum, weights the stratum results according to the original sample design parameters, and combines the weighted stratum results into class level results. The analysis provides hourly load estimates at both the stratum and class levels, and standard summary statistics, including non-coincident peaks, coincident peaks, coincidence factors, and load factors, at the class, stratum, and sample point levels.

The resulting class hourly load estimates are examined through various graphical approaches, the summary statistics are reviewed for consistency across time, and the monthly sample class energy results are compared against billed and booked billed and accrued values. Any anomalies are investigated, and a rate class analysis may be re-worked if the investigation shows that is necessary. When analysis and review of all rate classes is completed, losses are applied to the hourly rate class estimates, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the customer level load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary.

Rate classes are often comprised of combinations of commercial and industrial customers. Separate commercial and industrial hourly load estimates are developed after rate class analysis is completed. Monthly billing usage for each commercial and industrial customer is acquired from the customer information system and is imported into the Kema Load Research Analysis System, along with the sample point interval data available from the rate class random and 100% samples. The sample interval data is post-stratified and weighted to represent the commercial and industrial class populations, and total class hourly load estimates are developed. Losses are then applied to the resulting commercial and industrial class estimates, the values are combined with the residential class hourly load estimates from the rate class analysis, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary. Final residential, commercial, and industrial class hourly load estimates are provided to the forecasting organization for use in the long-term forecasting and planning process.

O. Customer Self-Generation (170 IAC 4-7-4(4))

On May 18, 2005, I&M's net metering program became effective for residential and school customers operating small, renewable-resource generation facilities. Through 2010, 37 customers have signed up for this program.

However, customer self-generation (including co-generation) historically has been minimal in the I&M service territory. For a variety of reasons, including the price of electricity, I&M customers generally have not found self-generation to be cost effective. The underlying factors that limit self-generation are not expected to significantly change in the future and, therefore, customer self-generation did not affect projected load during the forecast period.

4) DEMAND SIDE MANAGEMENT

4. Demand Side Management (170 IAC 4-7-6(a) (7); 4-7-6(b); 4-7-7(b) through (f))

A. Introduction

I&M currently offers a variety of conservation and demand-side management (DSM) programs designed to encourage customers to become more aware of their consumption levels, use electricity efficiently, conserve energy, and use appropriately incentivized, cost-effective electro-technologies. The load impacts of these programs are embedded in I&M's actual load experience and its load forecast.

Prior to 2007, various factors, primarily low avoided costs for energy and demand, resulted in I&M offering a variety of DSM-related tariffs only. I&M's robust reserve of relatively low cost capacity created challenges in the justification and promotion of cost-effective demand-side management and energy efficiency programs.

As discussed in Chapter 3, the characteristics of the current and projected I&M customer load are different today than they were in the past. Although significant gains in end-use efficiency have been achieved from government standards, changes in the marketplace, and customer choices and behavior, a depressed economy and the governments' stimulus activity has recently intensified the focus and desire for energy efficiency. A heightened sensitivity of environmental issues and the desire for all things "green" have also escalated in recent years. As a result, in 2007, I&M proposed to implement energy efficiency programs that would promote and incent the purchase and installation of more efficient end-use electro-technologies that would help customers reduce their consumption. Through settlement efforts and approval from the Commission, I&M, as a member of the Program Implementation Oversight Board, implemented seven third-party designed energy efficiency programs during 2010. In compliance with the

Commission's Phase II Generic Order, Cause 42693, issued on December 9, 2009, I&M next developed a Three Year DSM Plan, Cause 43959, which contained Core and Core Plus Program offerings aimed at meeting and/or exceeding the energy savings goals set forth in the Generic Order. This plan was approved on April 27, 2011. Concurrent to I&M's initiation of energy efficiency programs since 2007, as discussed in Chapter 1.F. and in Chapter 4.E.1, AEP embarked on a system-wide project, referred to as gridSMART®. The gridSMART effort, which includes I&M's portfolio of energy efficiency programs, aims to create a holistic corporate-wide approach to incorporating technology, in part, to achieve increased efficiency in utility operations and to further develop potential DSM offerings to customers. I&M's existing energy efficiency programs are currently marketed under the gridSMART® umbrella and Core Plus Programs will be marketed in the same manner.

B. Current DSM Programs

I&M has seven energy efficiency programs implemented, five of which are Core Programs (or similar to Core Programs). The remaining two are Core Plus Programs. Core Programs will be transitioned to the Third Party Administrator for implementation in January, 2012 on a statewide basis as directed in the Phase II Generic Order. The two Core Plus Programs will continue to be implemented by I&M as part of the Three Year DSM Plan Core Plus portfolio. The seven programs currently implemented include Residential Rebates (Lighting), Residential Low & Moderate Income Weatherization, Residential Home Energy Audit (audits, direct installs, and weatherization), Energy Efficient Schools (education & take home kits), C&I Prescriptive, Residential Appliance Recycling, and C&I Custom. A listing of the eighteen programs contained in I&M's

Three Year DSM Plan is provided in the Short Term-Action Plan section of this report.

C. I&M Demand Side Management Status

In both I&M's Indiana and Michigan jurisdictions, annual energy efficiency targets have been mandated (Enrolled Senate Bill 213 – Michigan, Cause No. 42693 Phase II Order – Indiana). The Michigan requirement, which took effect in late 2008 seeks to achieve 10.55% of installed energy savings by 2020 while the Indiana requirement, which began in 2010, seeks to achieve 11.9% installed energy efficiency by 2019. This plan reflects compliance with those mandates.

To that end, this plan reflects current program impacts as well as impacts from as yet undefined future programs. Impacts are modeled based on load shapes that best replicate current and likely future programs. Prospective program composition is extrapolated from the current mix of programs and measures. The ultimate mix of Indiana programs will be determined through the collaborative process of the I&M Program Implementation Oversight Board, the DSM Coordination Committee, the State-wide Third Party Administrator and the Commission.

To achieve the goals, a mix of traditional consumer programs and smart grid technologies will likely be necessary and both are considered in this IRP. AEP remains internally committed to install measures designed to achieve system-wide peak demand reductions of 1,000 MW and energy reductions of 2,250 GWh by year-end 2012. Since 2008 and through the second quarter of 2011, over 500 MW and 1,320 GWh of EE and DR have been installed on the AEP-East System. It is expected that I&M Indiana will achieve 51 MW and 265 GWh, from 2008 -2012.

D. Program Types

1. Consumer Programs

Energy efficiency measures save money for customers billed on a "per kilowatt-hour" usage basis. The trade-off is the reduced utility bill for any up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him or her back in the form of reduced bills over an acceptable period, he or she will adopt it.

EE measures include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances, most commonly. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will, in all cases, reduce the amount of energy consumed, but some measures may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. According to a March 2007 DOE study such benefits include:

Economics	Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
Environment	Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change
Infrastructure	Lower demand lessens constraints and congestion on the electric transmission and distribution systems
Security	EE can lessen our vulnerability to events that cut off energy supplies

Numerous studies have been published which quantify the amount of available "cost-effective" EE. Typically, and for the purposes of this IRP, this has meant measures that pass the "total resource cost" (TRC) test, meaning that the measure "pays for itself" in energy and capacity savings, regardless of whether or not its cost may be subsidized by the utility. The results of some notable studies are summarized below:

	Economic Potential		
Study	Utility Programs	Other	Total
EPRI 2009 (National)	13%	N/A	N/A
Forefront Economics 2008 (I&M Indiana)	16%	N/A	N/A
McKinsey & Company 2009 (National)	N/A	N/A	23%
MEAA Residential 2006 - (Michigan)[1]	13%	N/A	N/A
MEAA Residential 2006 - (Indiana)[1]	13%	N/A	N/A
Black & Veatch 2009 (I&M Michigan)	27%	N/A	N/A

[1] Includes subset of Technical Potential with levelized cost less than $100/MWh.

While there is some disagreement about what the actual number may be and some differences in methodologies, it is reasonable to assume that there is a fairly large well of latent cost-effective EE available. What becomes a question of policy is how much of the available efficiency should be pursued with utility-sponsored programs, and included as a resource.

Unlike supply-side resources, demand-side resources, particularly EE resources require the participation of thousands of consumers. While the math may indicate that an "investment" in a particular measure is cost-effective, it does not guarantee that it will be universally adopted.

Market barriers to EE exist which limit the rate and ultimate level at which efficiency measures are adopted by consumers (program participants).

Market Barriers to Energy Efficiency	
High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of EE options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for EE services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the EE measure may be different from those benefiting from the investment (e.g. rental property).
Product/Service Unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings.

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

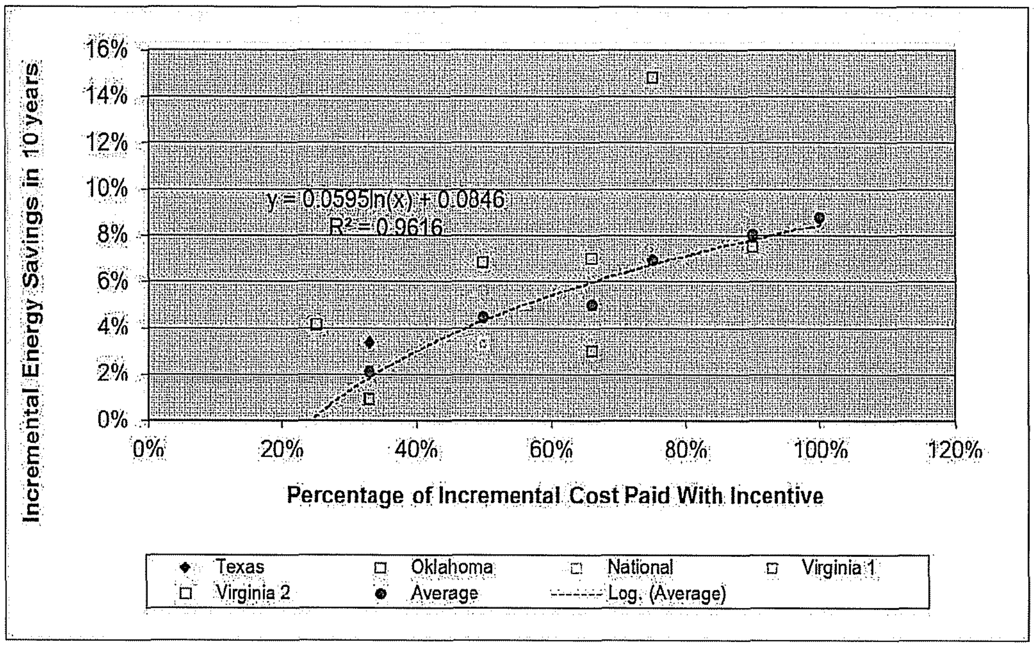
To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- Consumer education
- Technical training

- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of market transformation and measure adoption. To achieve rapid adoption of efficiency measures, it is reasonable to expect increased program costs associated with higher consumer incentives, higher administrative burdens and marketing. A market penetration function was derived from market potential studies for I&M and other AEP jurisdictions. Figure 4-1 shows that higher levels of EE can be achieved as the subsidies to participants (incentives) are increased. It also shows an intuitive degree of diminishing returns where increases in the incentive (expressed as a percentage of the measure cost) have a decreasing effectiveness.

Figure 4-1: Relationship Between Energy Savings and Subsidies



Source: Resource Planning

2. Smart Meters: gridSMART® ‾ Smart Meter Pilot Program

In March 2011, Indiana Michigan Power Company collaborating with the Indiana Office of the Utility Consumer Counselor documented their findings and recommendations pertaining to the Smart Meter Pilot Program (SMPP or Pilot) in South Bend, Indiana. The pilot included approximately 9,600 advanced metering infrastructure (AMI) smart meters. Among other grid reliability objectives, the Pilot sought to define the potential impact of advanced consumer programs on customer energy consumption, peak demand and energy cost.

Advanced consumer programs were introduced to provide customers a better way to control energy consumption and cost. The first was an advanced time-of-day (TOD) tariff for both residential and commercial customers. The initial residential off-peak rate was 5.4 cents/kWh and the on-peak rate was 16.8 cents/kWh; whereas, the commercial off-peak rate was 7.0 cents/kWh and the on-peak rate was 18.1 cents/kWh. A total of 146 residential customers and 1 commercial customer enrolled in this program. This exceeded the initial established residential goal of 50 customers and exceeds the 12 residential customers in the SMPP area that are on I&M standard TOD rate. However, the total participation of 146 (2.2%) residential qualifying SMPP customers and one commercial customer indicates an overall weak customer response to the advanced TOD tariff offerings.

The second advanced offering was a residential cooling direct load control (DLC) program offered in conjunction with the installation of a Programmable Communicating thermostat (PCT) installed in the home. The PCT allowed the temperature of the home to be adjusted upward a maximum of 4°F degrees during summer peak times in exchange for a monthly bill credit. I&M capped the number of program participants at 126 due to PCT technology issues. Program participation was well below the projected 500 customer goal set prior to the implementation due to these technology-related issues and a lack of customer participation.

The SMPP demonstrated that customers can accrue tangible benefits from smart grid deployments. First and foremost, those limited number of customers (2.2%) willing to participate in peak period time differentiated tariff programs, and those that actively participated, will reduce their peak demand, shift energy consumption out of the on-peak period, reduce total energy consumption and save money. Customers enrolled in the TOD rate program reduced their summer peak demand by 10.8% (.21kW) and their annual energy consumption by 1.5% (150kWh). These results compared favorably to the hypothesized 3.5% energy and peak demand reductions. TOD program customers saved an average of $28 annually representing a 3.6% reduction in their electric bill. Annual savings accrued to approximately 75% of the program participants with a vast majority of the savings occurring from September-May when all energy usage was priced at the discounted off-peak rate. The overall satisfaction rate for the program was 83% and no customers left the program except those who left the service territory.

I&M conducted eight DLC events in 2009 and 12 in 2010. Due to technology limitations and low implementation level in 2009, only data from 2010 events was analyzed to determine the program impact. Two types of events were conducted in 2010: 1) adjust the temperature a total of 4 degrees in two-2 degree steps and 2) adjust the temperature a total of 4 degrees in one step. The peak demand reduction from these adjustments was 1.2 kW per participant and the average demand reduction over a four-hour timeframe was 1.03 kW. The peak demand reduction represents a 43% decrease in normal customer demand. This reduction compares favorably to the original projection of a pre-program 1 kW reduction per customer. The limited participating DLC customers, on average, reduced annual energy consumption by 0.5% (50kWH) and saved $40.30 annually representing a 4.6% reduction in their electric bill. Overall program satisfaction rate was 88% and only one person exited the program without leaving the service territory. However, these DLC customers when allowed to override the load control programs without limitation or energy cost penalties tended to do so and ultimately reduce achievable demand savings.

Customers were able to view and analyze consumption data using the interactive web portal to identify ways to further conserve energy and save costs. Thirty-four percent of the SMPP area customers signed up on the I&M web site which increased the registrants from approximately 300 prior to the Pilot to almost 3,200 in September, 2010. While many customers registered to use the web site, a vast majority of the customers said they had not viewed their usage (87%). There was no discernible difference between the group of customers with web access to their consumption information and those who did not register for the web.

In summary, I&M believes the SMPP demonstrated the following:

- An integrated set of smart grid technologies and advanced customer programs can allow customers the ability to reduce their energy and peak demand consumption and save money;
- While the smart grid deployments provide the utility with some operational benefits, it is projected these distribution benefits alone do not exceed the entire cost of an integrated smart grid deployment. What is needed is active residential, commercial and industrial customer participation and a thorough understanding of energy cost benefits from a smart grid application; and

- SMPP was a unique limited scope test program where I&M customers did not pay for the Pilot deployment. Yet, even with an extensive advertising campaign only 2.2% of customers who had access to the SMPP programs bothered to participate despite clear financial incentives designed to elicit their participation. Based on I&M business modeling, a minimum customer participation rate of between 11% to 25%, with equal participation between tariff offerings, will be required. The SMPP and previous experience from the standard time of day tariff suggests voluntary customer participation rates in excess of 10% will be very difficult to achieve. Furthermore, while many customers registered to use the interactive web portal, 87% of customers never checked their energy usage. <u>Substantially greater customer interest will be necessary in order to justify the cost of this or similar future programs.</u>

3. Demand Response

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. In the PJM zone, this maximum (System peak) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. In addition to "passive" or "non-dispatchable" resources like EE and Integrated Volt VaR Control (IVVC), "active" or "dispatchable" resources, which have impacts primarily only at times of peak demand, include:

- *Interruptible loads*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.

- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through various media such as FM-radio signals that activate switches, or through a digital "smart" meter that allows activation of thermostats and other control devices.

- *Time-differentiated rates.* Offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) and to as often as 15-minute increments known as "real-time pricing." Accomplishing real-time pricing would typically require digital (smart) metering to "download" pricing signals from a utility host system.

In addition to the demand response (DR) program associated with the SMPP, I&M has interruptible contracts with larger customers amounting to 258MW of realized capacity reductions coincident with PJM's peak. Additional peak demand reduction capability is being pursued with the introduction of tariff-based DR offerings for C&I customers.

Expanding DR options beyond interruptible industrial contracts is likely necessary to achieve increased peak demand reductions. Many commercial businesses participate in DR activities that selectively reduce load in exchange for capacity payments from PJM. For this IRP, it is assumed that future demand reduction programs would consist of additional tariffs (summer and winter impacts) as well as Company-offered, summer-only DR similar to what is currently required within PJM.

On a broad scale, direct load control-type programs are typically more expensive as similar infrastructure is needed to achieve smaller load reductions. Moreover, these programs can also introduce consumer dissatisfaction since the "economic choice" is removed from the customer.

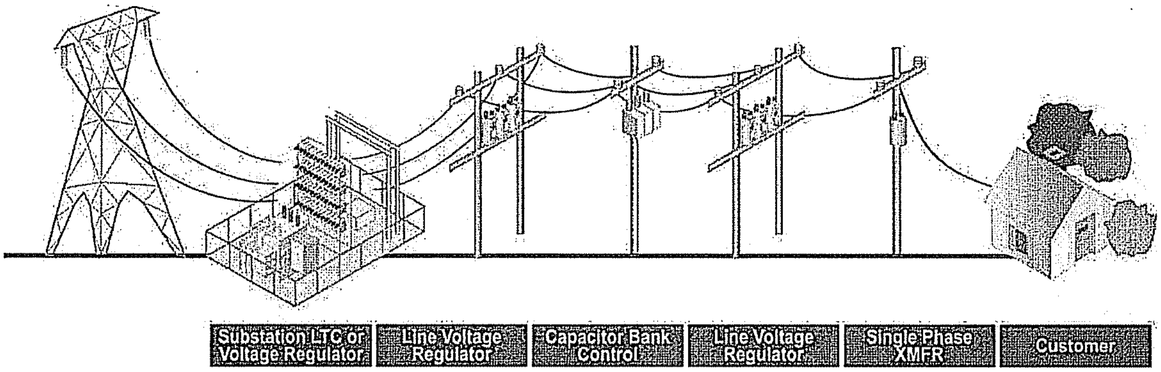
This IRP assumes a modest level of incremental DR to be met in part with PJM-compliant tariffs. Other options, including residential DR may also be considered in the future.

4. Integrated Volt VaR Distribution Infrastructure

Integrated Volt VaR Control (IVVC) provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, IVVC enables conservation voltage reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. A 1% reduction in voltage typically results in a 0.5% to 0.7% reduction in load.

As the electric infrastructure was built out in the last century, distribution systems were designed to ensure end-users received voltages ranging from 114 to 126 volts in accordance with national standards. Most utility systems were designed so that customers close to the substation received voltages close to 126 volts and customers farther from the substation received lower voltages. This design kept line construction costs low because voltage regulating equipment was only applied when necessary to ensure the required minimum voltages were provided. However, since most devices operated by electricity, especially motors, are designed to operate most efficiently at 115 volts, any "excess" voltage is typically wasted, usually in the form of heat. Tighter voltage regulation, enabled by smart-grid infrastructure, allows end-use devices to operate more efficiently without any action on the part of consumers (Figure 4-2). Consumers will simply use less energy to accomplish the same tasks.

Figure 4-2: Integrated Voltage/VaR Control



Source: Resource Planning

5. Technologies Considered But Not Evaluated

Distributed Generation to include roof-top solar, microturbines, combined heat and power (CHP), and residential and small commercial wind.

Currently, these technologies cost more than other options and were not considered for wide-scale utility implementation. Their costs will continue to be monitored.

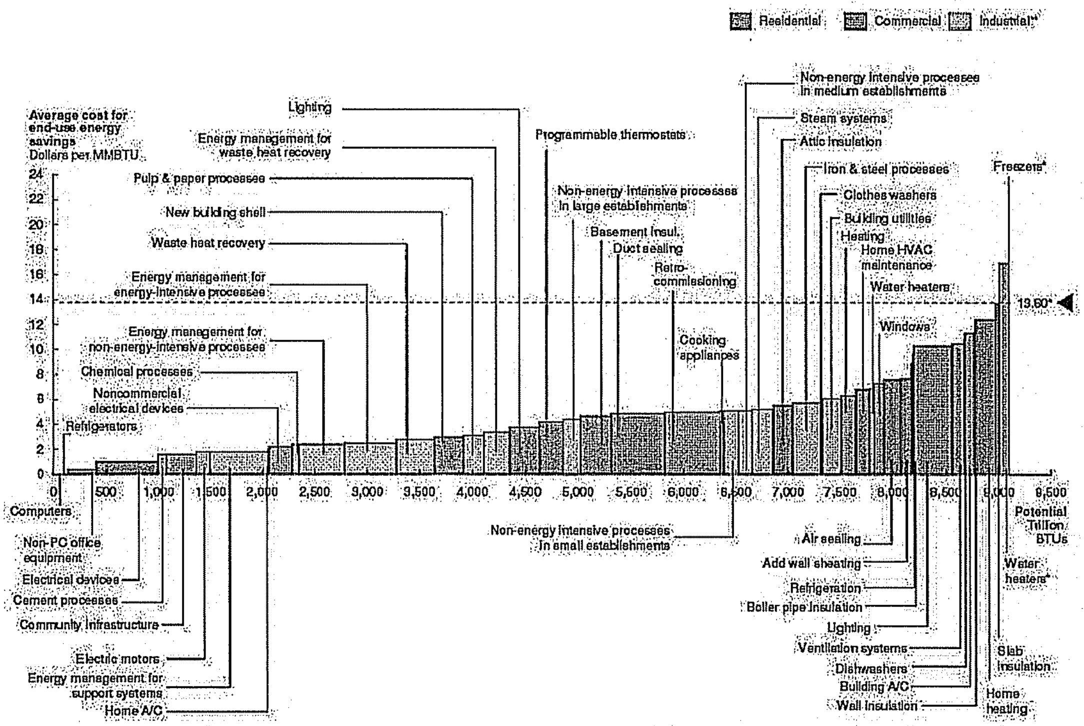
	Mean installed cost ($/kW)	Installed cost range (+/- $/kW)	Fixed O&M ($/kW-yr)	Fixed O&M (+/- $/kW-yr)	Variable O&M ($/kWh)	Variable O&M (+/- $/kWh)	Annual degradation rate (%/yr)
PV	$ 6,200	$ 1,200	$ 21	$ 6			0.5% to 0.8%
Wind 1 to 19kW	$ 7,500	$ 2,300			$ 0.02	$ 0.01	
Wind 20 to 100kW	$ 5,200	$ 1,800	$ 50	$ 20			
Wind 100 to 1000 kW	$ 2,500	$ 1,000	$ 50	$ 20			
Biomass Combustion CHP*	$ 5,500	$ 2,000			$ 0.09	$ 0.05	
* Unit cost is per unit kilowatt of the electrical generator, not the boiuler heat capacity							
Reproduced from: http://www.nrel.gov/analysis/pdfs/dg_lcoe_data.pdf							

E. Assessment of Demand Side Resources

1. Energy Efficiency

While EE measures have a wide range of costs and thus have a "supply curve" similar to other assets, as depicted in Figure 4-3, it is not practically true that the cheapest options will be exhausted first and ahead of more expensive options. Typically, a utility-sponsored program will be required to provide a portfolio of efficiency measures and programs which encompass a range along the cost curve.

Figure 4-3: EE Supply Curve



* Average price of avoided energy consumption at the industrial price; $35.60/MMBTU represents the highest regional electricity price used; new build cost based on AEO 2008 future construction costs
** Our 49th source of savings, refining processes, offers no NPV-positive savings
Source: EIA AEO 2008, McKinsey analysis

When determining the cost of the resource portfolio as a whole, the levelized resource cost of the EE portfolio, in aggregate, was assumed to be $40/MWh which is consistent with numerous studies (approximately equivalent to $4.00/MMBtu). The absolute value is not critical to verifying cost-effectiveness as will be shown. The real variable from the perspective of the utility and utility commissions is how much will a program cost and what results can be expected.

By evaluating the load forecast with and without EE, the difference can be considered the value, or benefit of the efficiency portfolio. This can then be compared to the costs of the EE portfolios. Because the per-unit cost of the measures are held constant, the variation in the portfolio costs (program costs) are due to the levels of EE and the incentive necessary to achieve those levels. Also, a break-even analysis was completed to determine the aggregate average measure cost that cannot be exceeded for the portfolio to be cost-effective from a total resource perspective.

The following table shows the costs and benefits of the Energy Efficiency embedded in the forecast given the assumption of an average resource cost of $4/MMBtu. Increases in that cost assumption will decrease the net benefits. This comprehensively analyzes current and future energy efficiency programs in the context of the dynamic modeling performed by *Strategist*, Cost-effectiveness of individual programs is discussed in the Short-term Action Plan.

Incentive Level	PV of Benefits ($000)	Nominal Program Costs ($000)	PV of Program Costs ($000)	Net Benefit ($000)
50%	979,229	334,525	208,001	771,228
75%	979,229	501,659	311,922	667,307
100%	979,229	668,893	415,905	563,324

The break-even, levelized cost of efficiency measures from a total resource cost perspective approached $10/MMBtu, or approximately $0.49/kWh installed. Program costs would be a fraction of these costs.

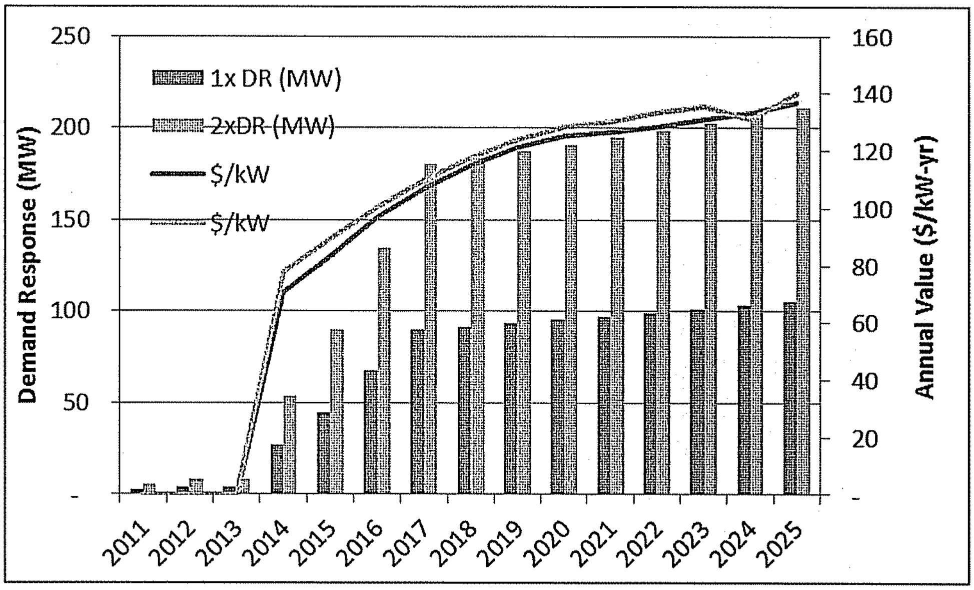
Because EE is an investment today for future savings and also results in spreading current fixed costs among fewer kilowatt hours, the net result is often an increase in rates, *even as* total bills (revenue requirements) decrease. Thus, a balance is sought between aggressive pursuit of efficiency and the full acknowledgement of this expected impact on rates.

A description of the current programs is included in the Short-term Action Plan.

2. Demand Response

As before, the base portfolio evaluation is completed with and without DR program/assets to determine its benefit. From there a break-even cost is calculated which becomes a cost-to-beat as DR options are pursued during the implementation phase. Additionally, as a sensitivity, the level of demand response assumed was doubled to gauge the benefits.

Figure 4-4: I&M Indiana Demand Response Values



As can be seen from Figure 4-4, demand response has little immediate value due to low capacity prices within PJM but very quickly ramps up. Achieving demand response at prices lower than shown in the graph will reduce the revenue requirement. A 100 MW reduction represents approximately 3% of peak load for all of I&M. However, that is incremental to current contracted interruptible load that already exceeds 7% of ultimate demand.

3. IVVC

Similar to EE, the base portfolio was prepared with *and* without IVVC and compared to the costs.

Annual Energy Savings (GWh)	Annual Peak Demand Reduction (MW)	PV Benefit ($000)	Capital Costs ($000)	PV Costs ($000)	Net Benefit ($000)
35	6.7	19,197	7,489	6,498	12,699

This result is somewhat scalable with the limit being available circuits that are worthwhile upgrading.

4. Smart Meters

Given the results of the smart meter pilot, incremental rollouts are not anticipated during the action period. However, residents who chose to participate in the load control feature can continue to participate. Residential (and Commercial) direct load control is a viable way to affect peak demand reductions, but it is not typically as economical as commercial load reductions.

5. Discussion and Conclusion

As a result of the requirements of the Indiana DSM Phase II order, an aggressive ramp up of energy efficiency programs is currently underway. The composition of the portfolio of programs is decided in an open, collaborative process. A summary of the current portfolio composition is included in Exhibit 10-1. I&M may benefit from further investment in demand response, particularly in the commercial and industrial space where costs are lower on a per unit basis. Further, investment in promising smart grid technologies like IVVC can reduce customer bills passively, skirting many of the barriers that inhibit rapid and universal adoption of traditional energy efficiency measures.

F. DSM and Distributed Generation: Distribution and Transmission Applications

The focus of this section up to this point has been on avoidance of generation. DSM and distributed generation (DG), including storage technologies such as Sodium

Sulfur (NaS) Batteries, also have the potential for greater use on the transmission and distribution system as technology improvements are made and costs are reduced.

For the distribution system, DG and DSM applications can be integrated with distribution switching technologies for peak shaving and/or reliability improvement applications. These DG systems will require the use of real time data to ensure that safety and power quality are maintained in the operation of the system. In peak shaving, DG application(s) would be activated based on operational factors so grid constraints are mitigated. These operational factors could include voltage, current, frequency and/or temperature indicators, which can be managed and used for decision-making through software applications or monitored by a system dispatcher. For reliability improvement applications, DG can strategically be placed on existing feeders and the feeder configured to automatically switch to "islanding" mode when the main station feed is interrupted. Islanding involves the electrical isolation of a portion of the feeder so that it can be safely and reliability fed from the DG application(s). This DG application will require real time data for determining the state of the local distribution grid and a robust communication system for timely and accurate processing of the data.

From a transmission planning perspective, DG and DSM are modeled as built-in inputs into the annual assessments. These inputs are established by PJM as part of the Reliability Pricing Model (RPM) and Base Case development effort. In the absence of these inputs, more transmission improvements could be required. As a member of PJM, any proposed solutions to transmission problems will be reviewed by PJM through its stakeholder process to ensure compatibility of the proposed solution on a regional basis.

Currently, DG technologies have a very high capital cost, particularly when sized conventionally to meet peak demand. If costs continue to decline as expected and new ways to utilize storage are conceived, it is possible that this technology will become a larger part of future resource plans.

G. Current Interruptible Service Rate Options

A contributor to the Company's demand-side management programs currently impacting the IRP is the set of interruptible and curtailment tariffs, riders and special contract agreements. These programs are currently offered to qualifying commercial and industrial customers along with, in some cases, certain market buy-through privileges.

I&M's interruptible service options provide industrial and commercial customers discounts in exchange for their agreement to temporarily curtail their service when requested. I&M's interruptible service options include Contract Service - Interruptible Power tariffs and demand response riders recently filed by the Company and approved by the IURC relating to emergency and economic interruptions. I&M also has an interruptible customer under a special contract arrangement.

The Company makes available Rider ECS, Emergency Curtailable Service (ECS) and Rider EPCS, Energy Price Curtailable Service (EPCS) to our commercial and industrial customers taking service under Tariff IP, Industrial Power. These additional interruptible service options address temporary, or short-term, emergency operating conditions on the AEP System. In the event of curtailments, such customers receive a curtailable credit based on the amount of energy curtailed and the respective pricing provisions of these riders.

I&M also offers interruptible service via PJM's Demand Response program. In compliance with the Commission's Order in Cause No. 43566 dated July 28, 2010, the Company began offering several demand response riders in Indiana providing customers additional opportunities to receive compensation / billing credit in exchange for curtailing demand and energy. These are PJM demand response programs where customers are only enrolled through the Company. The demand response riders include: Emergency Demand Response (D.R.S. 1), Economic Demand Response (D.R.S. 2) and Ancillary Service Demand Response (D.R.S. 3).

For the 2012 forecast year, and annually thereafter, it is anticipated that six interruptible customers with contracted interruptible capacity of approximately 375 MW. Based on historical load patterns and the particular nature of each interruptible contract, the estimated available interruptible load for purposes of this resource planning process is 243 MW (summer rating) for I&M. In addition to these interruptible customers, the Company has 19 demand response and 106 direct load control customers that may be interrupted under certain conditions, with these customers having 40.5 MW of demand reduction capacity.

H. Current Time-Of-Use Service Options

Another contributor to I&M's demand-side management programs include optional special rates with time-of-use "demand-side" features.

Some of I&M's tariffs contain features that are designed to encourage customers to shift load from the on-peak period to the off-peak period. Customers participating in these tariffs benefit from lower off-peak rates for energy and demand shifted to the off-peak period. Encouraging customers to shift their energy consumption to off-peak periods creates a win-win situation for I&M and its customers. Participating customers receive reduced rates and I&M has the potential to reduce costs and realize efficiency gains in producing electricity.

I&M offers a standard and an experimental time-of-day (TOD), storage water heater, load management time-of-day and off-peak forgiveness provisions to its customers. The standard time-of-day provision is available to all customers and provides on-peak and off-peak energy charges. The experimental time-of-day provision also provides on-peak and off-peak energy charges and is available to those customers located within the former South Bend Smart Meter Pilot Program (SMPP) area and a limited number of customers outside of the SMPP. The load management time-of-day provision is available to customers who use energy-storage devices with time-differentiated load characteristics (generally equipment operating only during the off-peak hours). The off-peak forgiveness provision disregards, for billing purposes, demand created during the off-peak hours up to certain tariff limitations. Over 3,000 Indiana customers are presently served on TOD tariffs, and over 16,100 residential customers have installed off-peak water heater systems.

The rates associated with time-of-use are designed to reflect the different costs the Company incurs in providing electricity during peak periods when electricity demand is high and off-peak periods when electricity demand is low. I&M's on-peak period is defined as 7 A.M. to 9 P.M., Monday through Friday. The off-peak period is all other hours not defined during the on-peak period.

Whether customers benefit from time-of-use rates is contingent upon the percentage of total consumption used during on-peak periods, or rather, how much usage is shifted from the on-peak period to the off-peak period.

Listing of I&M's Time-Of-Use, Interruptible and Demand Response Tariffs

As mentioned above, I&M provides tariffs that encourage customers to make energy-efficient and cost saving decisions by participating in time-of-use and interruptible load programs.

A description of these time-of-use and interruptible service options are shown in Time-Of-Use, Interruptible and Demand Response Tariffs – Table 1 shown directly below.

Time-Of-Use, Interruptible and Demand Response Tariffs – Table 1

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
RS-TOD	Time-Of-Use	Available to single-phase residential customers. This tariff provides on-peak and off-peak energy charges. Limited to first 2,500 customers (Indiana).	Indiana, Michigan	5,513
RS-TOD2	Time-Of-Use	Experimental program available to single-phase residential customers located within the former South Bend Smart Meter Pilot Program (SMPP) area and a limited number of customers outside of the SMPP. This tariff provides on-peak and off-peak energy charges.	Indiana	140
RS-OPES (RS-OPES/PEV in Michigan)	Time-Of-Use	Available to customers eligible for Tariff RS (Residential Service) who use approved energy storage devices with time-differentiated load characteristics, such as electric thermal storage space heating equipment and water heaters that consume electrical energy only during off-peak hours and store it for use during on-peak hours.	Indiana, Michigan	1,394

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
RS-LMWH/SWH	Time-Of-Use	Provision available for residential customers who install a company-approved load management water heating system with capacity of at least 80 gallons, which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak. The last 250 kWh of use in any month shall be billed at an off-peak energy charge. The storage water heating provision is withdrawn except for the present installations of current customers receiving service at premises served prior to May 1, 1997.	Indiana, Michigan	17,167
Rider DLC-2	Interruptible	Experimental program available to residential customers located within the former South Bend Smart Meter Pilot area under which customers authorize the Company to install a smart thermostat device to control the customer's central electric cooling unit.	Indiana	106
Rider R.P.R.	Interruptible	Available on a voluntary basis for customers receiving residential electric service. Customers cannot take service under this Rider while also taking service under Rider D.L.C or Rider D.L.C.-2. To participate, customers allow the Company to install load control equipment and, if necessary, auxiliary communicating devices to control the customer's central electric cooling unit(s). The Company will utilize the installed control devices to reduce customer's energy use during load management events.	Indiana	0

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
SGS-LMTOD	Time-Of-Use	Available to customers who use approved energy-storage devices with time-differentiated load characteristics, such as electrical thermal storage space-heating and/or cooling systems and water heaters that consume electrical energy only during Company-specified off-peak hours and store energy for use during on-peak hours. These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	59
SGS-TOD	Time-Of-Use	Experimental program available to single-phase small general service customers located within the former South Bend Smart Meter Pilot Program (SMPP) area and a limited number outside the SMPP. This tariff provides on-peak and off-peak energy charges.	Indiana	2
MGS-LMTOD	Time-Of-Use	Available to customers who use approved energy-storage devices with time-differentiated load characteristics, such as electrical thermal storage space-heating and/or cooling systems and water heaters that consume electrical energy only during Company-specified off-peak hours and store energy for use during on-peak hours. These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	144
LGS-TOD	Time-Of-Use	Available to general service customers with demands greater than 10 kW but less than 1,000 kW. This tariff provides on-peak and off-peak energy charges.	Indiana	11

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
LGS-LMTOD	Time-Of-Use	Available to customers who use approved energy-storage devices with time-differentiated load characteristics, such as electrical thermal storage space-heating and/or cooling systems and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours. These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	25
MGS-TOD	Time-Of-Use	Available for general service customers with demands greater than 10 kW but less than 150 kW (Indiana) and zero to 150 kW (Michigan). Electric service will be measured through one multi-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods. This tariff provides on-peak and off-peak energy charges.	Indiana, Michigan	1,264
LGS (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with maximum demands greater than 60 kVA but less than 1,000 kVA (Indiana) and greater than 100 but less than 1,500 kW (Michigan). Demand created during the off-peak hours is disregarded for billing purposes provided that the billing demand is not less than 60 percent of the maximum demand created during the billing month nor less than 60 percent of either (a) the contract capacity, (b) the customer's highest previously established monthly billing demand during the past 11 months, or (c) 100 kVA.	Indiana, Michigan	1,906

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
LP (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with contracted capacity of 1,500 kW. Demand created during the off-peak hours is disregarded for billing provided that the billing demand is not less than 60% of the maximum demand created during the billing month, nor less than 1,500 kW nor less than 60% of the contract capacity.	Michigan	26
LP (Time-Of-Day Energy Charges)	Time-Of-Use	Available for general service customers with contracted capacity of 1,500 kW or greater under Tariff LP. This tariff provides on-peak and off-peak energy charges.	Michigan	Customers included in the previous tariff schedule.
IP (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with normal maximum requirements of 1,000 kVA or greater. Demand created during the off-peak hours is disregarded for billing purposes provided that the billing demand is not less than 60% of the maximum demand created during the billing month nor less than 60% of either (a) the contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.	Indiana	231

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
WSS (Optional TOD)	Time-Of-Use	Available for the supply of electric energy to waterworks and sewage disposal systems who consume metered usage during off-peak periods. Customers with normal maximum demands of 100 kW or more (Michigan only) have the option to receive this service. This tariff provides on-peak and off-peak energy charges.	Indiana, Michigan	3
EHS (Off-Peak Hour Provision)	Time-Of-Use	Not available for new applications. Available to primary and secondary schools and to college and university buildings where the principal energy requirements (all lighting, heating, cooling, water heating, and cooking) are provided by electric energy. Demand created during the off-peak hours is disregarded for billing purposes provided that the billing demand is not less than 60 percent of the maximum demand created during the billing month. Note: This tariff has been withdrawn except for existing installations.	Michigan	47
CS – IRP	Interruptible	Available to customers operating at 34 kV or higher who contract for service under one of the Company's interruptible service options. The total contract capacity for all customers served under this tariff and Tariff IRP is limited to 135,000 kVA. This tariff has been withdrawn except for existing installations.	Indiana	3

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
CS-IRP2	Interruptible	Available to customers with interruptible demands of 1,000kW/kVA who contract for service under one of the Company's interruptible service options. The total contract capacity for all customers served under this tariff, Tariff CS-IRP, and Riders DRS1 and DRS2 is limited to 235,000 kVA in Indiana and 50,000 kW in Michigan.	Indiana, Michigan	5
Special Interruptible Contract	Interruptible	Special Contract provides for curtailment of load.	Indiana	1
Rider ECS (Emergency Curtailable Service)	Interruptible	Rider ECS is available to customers normally taking firm service under Tariff IP (Indiana) or Tariff LP (Michigan) for their total capacity requirements from the Company. Customer's ECS load will be curtailed when an emergency condition exists on the AEP System. The customer must have an on-peak curtailable demand not less than 1 MVA and will be compensated for kWh curtailed under the provisions of Rider ECS. Customer selects one of two ECS curtailment options based upon maximum duration and credit amounts. Customer will be subject to curtailment for no more than 50 hours per season.	Indiana, Michigan	0
Rider EPCS (Energy Price Curtailable Service)	Interruptible	Rider EPCS is available to customers normally taking firm service under Tariff IP (Indiana) or Tariff LP (Michigan) for their total capacity requirements from the Company. Customer's PCS load	Indiana, Michigan	0

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
		will be curtailed at the Company's sole discretion. The customer must have an on-peak curtailable demand not less than 1 MW/MVA and will be compensated for kWh curtailed under the provisions of the Rider. Customer selects one of three EPCS curtailment duration options. Customer specifies the maximum number of days during the season that the customer may be requested to curtail. Indiana customers select notification on a day ahead and/or current day basis. The customer also specifies the minimum price at which the customer would be willing to curtail. The Company, at its sole discretion, determines whether the customer will be curtailed given the customer's specified PCS curtailment options.		
D.R.S.-1	Interruptible	Available to commercial and industrial customers who have the ability to curtail load under the provisions of this demand response emergency rider and receives a payment each month. The Company will directly enroll customers in the PJM Emergency Demand Response Program.	Indiana	16
D.R.S.-2	Interruptible	Available to commercial and industrial customers who voluntarily respond to locational marginal prices (LMP) by reducing consumption and receives a payment for those reductions during times when LMP prices are high. The Company will directly enroll customers in the PJM Economic Demand Response Program.	Indiana	0

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
D.R.S.-3	Interruptible	Available to commercial and industrial customers who have the opportunity to offer demand response to meet the needs of the transmission system and receive a payment or credit for such demand response. The Company will directly enroll customers in the PJM Economic Demand Response Program.	Indiana	0
Utility Residential Weatherization Program (URWP)	Weatherization	Upon customer request, I&M may provide financial assistance in the form of loans to residential customers for the cost of certain energy conservation measures. Qualified homes must use electricity for space heating or air conditioning. After I&M conducts the Residential Conservation Service Program audit, the Company will assist the customer to install energy conservation measures by financing the cost of such conservation measures in amounts up to $1,500 with a maximum repayment period of three years.	Indiana	17

Note 1: I&M-Indiana and I&M-Michigan's standard off-peak billing period is defined as 9 p.m. to 7 am, local time, Monday through Friday including all hours of Saturdays and Sundays. I&M-Indiana's experimental off-peak billing period used in the former South Bend Smart Meter Pilot area is defined as midnight to 2 p.m. and 6 p.m. to midnight May through September and all hours October through April.

Note 2: The Utility Residential Weatherization Program shown in the table above is offered by the Company to its customers through its provision within I&M-Indiana's Terms and Conditions of Service.

Note3: The tariff descriptions shown above are in summary form. To obtain a full description, please see the Company's tariff sheets and Terms and Conditions of Service.

The Time-Of-Use Demand Reduction – Table 2, shown below, reflects I&M's demand reduction in MW for each off-peak tariff schedule as of September 2011.

Time-Of-Use Demand Reduction - Table 2

Class	**Coincident Peak Demand Reduction (MW)**
Residential LMWH	3.1
Residential WH80	0.3
Residential WH100	0.2
Residential WH120	2.0
Residential TOD2	0.0
Residential TOD	0.1
Residential OPES	0.1
MGS LMTOD	0.4
SGS TOD & LMTOD	0.0
MGS TOD	2.4
MGSTOD3CO	0.0
LGS LMTOD	1.0
LGS TOD	0.2
IP Primary	6.3
IP Subtrans	1.4
IP Transmission	1.8
IP Secondary	3.3
Total	22.8

5) SUPPLY-SIDE RESOURCES

5. Supply-Side Resources

A. Introduction

Supply-side resources include existing and new utility-scale sources that can supply the electrical energy requirements of I&M's customers. This chapter describes existing capacity and other bulk power arrangements, expected changes to existing capacity, including potential retirements, and the screening of potential new resources.

B. Existing Pool and Bulk Power Arrangements (170 IAC 4-7-6(a) (5) and 170 IAC 4-7-6(c) (4))

1. AEP Interconnection Agreement

The current planning and operation of the generation facilities of the five major operating companies in the AEP System's-East Zone, including I&M, is coordinated through the AEP Interconnection Agreement. The AEP Interconnection Agreement, commonly referred to as the "pool agreement," was originally signed in 1951 and has been modified and supplemented from time to time since then. The AEP Pool allows each of the members to receive the economies of scale that result from a large system.

The pool agreement provides a mechanism to compensate individual operating companies for imbalances that may exist from time to time with respect to the installed generating capacities of the AEP Pool member companies. Under the accounting provisions of the pool agreement, each member is responsible to provide for its member load ratio of the total AEP Pool generating capacity. Member load ratio for each month is the ratio of the Company's peak load during the prior twelve months to the sum of the five companies' non-coincident peak loads during the same period. Each capacity-surplus AEP Pool member is credited on a monthly basis for its surplus capacity in excess of this requirement, and receives payments from the capacity-deficit members, at a rate that reflects the embedded investment cost of its own primary steam capacity and the fixed operating rate of this capacity. These payments to the capacity-surplus AEP Pool members are made by the capacity-deficit members, in proportion to their respective capacity deficits. Payments are made at the primary capacity equalization rate for the AEP Pool, which reflects the weighted average of the embedded investment cost of primary steam capacity and the fixed operating rates of all the capacity-surplus members. I&M is currently a capacity surplus member.

As stated in Section 2.A., on December 17, 2010, each of the AEP Pool members gave written notice to the other members, and to AEPSC, of its intent to allow for modification of the pool agreement, effective January 1, 2014 or such other date as approved by FERC. Because the AEP Pool agreement is a rate schedule on file at FERC, its modification will not be effective until accepted for filing by FERC.

2. AEP System Transmission Agreement

The AEP System Transmission Agreement, updated and approved by FERC Order on October 29, 2010, provides for the sharing among the members of the East Zone, including I&M, of the costs incurred by the members for the ownership, operation, and maintenance of their portions of the high voltage transmission system, in order to enhance equity among the members for the continued development of a reliable and economic high voltage system. Members having high voltage transmission investments greater than their respective load shares receive payments from members with investments less than their respective load shares.

3. PJM Membership

On October 1, 2004, the AEP System-East Zone, including I&M, joined the PJM Interconnection. PJM is a FERC-approved regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. PJM manages a regional planning process for expansion of the transmission system and continuously monitors the transmission grid. PJM operates a competitive wholesale electricity market and dispatches the generating units of its members, based on energy offers made by the members, seeking to provide the lowest possible cost of electricity within its footprint. PJM sets generation planning reserve requirements for its members *(Refer to Chapter 2 section D).*

4. OVEC Purchase Entitlement

Four AEP companies (APCo, CSP, I&M and OPCo) are among the owners of the Ohio Valley Electric Corporation (OVEC) and its subsidiary Indiana-Kentucky Electric Corporation (IKEC). At this time, I&M's share of the OVEC units' capacity is approximately 18.06%.

C. Existing Units (170 IAC 4-7-4 (7) and 170 IAC 4-7-6 (a) (1)-(3))

1. Current Supply

Exhibit 5-1 offers a summary of all existing supply resources for the AEP System-East Zone and for I&M as of June 1, 2011. Figure 5-1 summarizes the data in Exhibit 5-1 and also includes, for information, the PJM RTO installed capacity (including purchases) by fuel type as of May 31, 2011 (http://www.pjm.com/~/media/markets-ops/ops-analysis/capacity-by-fuel-type-2011.ashx). Total PJM RTO capacity is 181,619 MW of which 39.70% is coal fired, 34.08% is gas/oil and 18.50% is nuclear. The 2011 summer I&M capacity of 5,546 MW and the 2011 summer AEP System - East Zone capacity of 27,999 MW are composed of the following resource types (MW):

Figure 5-1

2011 Generating Capacity

	I&M	East Zone	PJM RTO
Coal	3,208	20,991	72,098
Nuclear	2,059	2,059	33,600
Hydro/Pumped Storage	12	684	7,821
Gas Diesel	0	2,821	46,975
Oil	0	0	14,923
Purchase	242	1,329	4,040
Renewable	25	116	2,163
Total	5,546	27,999	181,619

Note: Totals do not include DSM/EE program values

2. Current (Embedded) Capability Adjustments

The capability forecast of the existing AEP System-East Zone generating fleet over the 2012-2031 forecast period reflects a reduction of approximately 111 MW as a result of unit deratings associated with environmental facility retrofit, and Coal-to-Gas unit conversions, netted against upgrades associated with planned efficiency improvements.

Output changes to I&M generating units are shown in Figure 5-2 as well as Exhibit 5-2. Note that while Figure 5-2 and Exhibit 5-2 both show specific technology additions to Rockport, a decision as to the particular Rockport Unit that will be first retrofitted is still being evaluated.

Figure 5-2

Year	Month	Unit	Modification	Capacity Change (MW) Total Unit	I&M
2014	1	Tanners 4	FGD (DSI)	0	0
2014	1	Rockport 2	FGD (Technology TBD)	0	0
2015	1	Tanners 1	Retirement	-145	-145
2015	1	Tanners 2	Retirement	-145	-145
2015	1	Tanners 3	Retirement	-195	-195
2016	1	Rockport 1	Turbine Steam Path Upgrade + FGD	0	0
2016	1	Rockport 1	Seasonal Derate Removal	10	9
2020	1	Rockport 2	Turbine Steam Path Upgrade	35	30
2025	1	Tanners 4	Retirement	-500	-500
				-940	-947

3. Fuel Inventory and Procurement Practices.

a. General

The generating units of I&M and the other AEP System-East Zone operating companies, which are predominantly coal-fired, are expected to have adequate fuel supplies to meet full-load burn requirements in both the short-term and the long-term. AEPSC, acting as agent for I&M, is responsible for the procurement and delivery of coal to I&M's generating stations, as well as setting coal inventory target level ranges and monitoring those levels. AEPSC's primary objective is to assure a continuous supply of quality coal at the lowest cost reasonably possible. Deliveries are arranged so that sufficient coal is available at all times. The consistency and quality of the coal delivered to the generating stations is also vitally important. The consistency of the sulfur content of the delivered coal is fundamental to I&M in achieving and maintaining compliance with the applicable environmental limitations.

b. Units

I&M has two coal-fired generating stations, Rockport and Tanners Creek, both in Indiana. The Rockport Generating Station, located in Spencer County, consists of two 1,300-megawatt coal fired generating units. Sulfur dioxide (SO_2) emissions at Rockport are limited to 1.2 lb. SO_2/MMBtu. Compliance with the emission limit is achieved by using a blend of Powder River Basin low sulfur sub-bituminous coal and low sulfur bituminous coal from Colorado or eastern sources. The Tanners Creek generating station is located in Dearborn County, and consists of four coal-fired units with a total Net Maximum Capacity (NMC) of 995 megawatts. In accordance with the NSR Consent Decree, Tanners Creek Units 1, 2, and 3 (TC 1-3) are limited to fuels with a sulfur content no greater than 1.2 lb. SO_2/MMBtu and Unit 4 (TC-4) is limited to fuels with a sulfur content no greater than 1.2%, with both sulfur content restrictions on the Tanners Creek units being enforced on an annual average basis. As a result of the different air emission standards, as well as differences in the boiler designs, the coal supplies for Tanners Creek 1-3 and Tanners Creek-4 vary in order to match the differing quality requirements of the units. The fuel for Tanners Creek 1-3 will be from bituminous sources located in Colorado and from eastern bituminous sources. Tanners Creek 4, similar to the Rockport Station, can use a blend of Powder River Basin coal from Wyoming and low sulfur bituminous coal from eastern sources.

c. Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. Sources of coal are established by taking into account contractual obligations and existing sources of supply. I&M's total coal requirements are met using a portfolio of long-term arrangements, and spot-market purchases. Long-term contracts support a relatively stable and consistent supply of coal. When needed, spot purchases are used to provide flexibility in scheduling contract deliveries, to accommodate changing demand, and to cover shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

d. Contract Descriptions

Rockport's need for coal is being supplied primarily through two long-term supply agreements with Peabody COALSALES, LLC.

The first long-term contract between I&M and Peabody COALSALES, LLC formerly known as the Rochelle Coal Company that began in October 1989 and was scheduled to expire at the end of 2004 has been extended by I&M and Peabody Energy Corporation with annual base tonnages scheduled through the term of the agreement. The second long-term agreement is in effect with Peabody COALSALES, LLC with deliveries of coal that commenced in January 2005 and continues under the terms of the agreement. In addition to these long-term contracts, there are several other committed contracts, both term and spot, that will contribute to fulfilling the supply requirements. Any remaining supply requirements will be fulfilled with non-committed purchases. As these agreements expire, additional coal supplies will be contracted to maintain a sufficient supply of coal.

Contract coal for Tanners Creek 1-3 will be supplied pursuant to the Bowie Resources, LLC Magnum Coal Sales LLC, and the Argus Energy LLC long-term agreements. The primary source of Tanners Creek 4 coal deliveries is the extended Peabody COALSALES, LLC long-term contract discussed above. In addition to these long-term contracts, non-committed coal will be purchased to maintain sufficient coal supplies.

e. Inventory

I&M attempts to maintain in storage at each plant an adequate coal supply to meet full-load burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, programs have been developed to conserve coal supplies. In the event of a severe coal shortage, I&M and the AEP System-East Zone operating companies would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan.

f. Forecasted Fuel Prices

I&M specific forecasted annual fuel prices, by unit, for the period 2012 through 2021 are displayed in Exhibit 1 of the Confidential Supplement.

4. Capacity Acquisitions and Dispositions

As part of its resource planning process, AEP continues to investigate the viability of placing indicative offers on additional utility or IPP-owned natural gas peaking and combined cycle facilities. On September 19, 2007, AEP completed the purchase of a natural gas-fired power plant under construction near Dresden, Ohio, from Dresden Energy LLC, a subsidiary of Dominion. With an expected Commercial Operation date in early 2012, Dresden will be a nominal 625 MW natural gas-fired combined-cycle plant owned by APCo.

Another important initial process within this 2011 IRP cycle was the establishment of a long-term view of disposition alternatives facing older, smaller currently uncontrolled coal-steam units in the I&M and AEP System-East fleet. Prior "Unit Disposition" analyses identified aging I&M and AEP-East generating assets consisting of a total of 26 units (including 4 I&M units) with a PJM (summer) rating of 5,348 MW (including 985 MW for I&M).

<u>I&M</u>

- Tanners Creek Units 1-3 (485 MW) IN
- Tanners Creek Units 4 (500 MW) IN

<u>APCo</u>

- Clinch River Units 1-3 (690 MW) VA
- Glen Lyn Unit 5 (90 MW) and Unit 6 (235 MW) VA
- Kanawha River Units 1 & 2 (400 MW) WV
- Sporn Units 1 & 3 (290 MW) WV

<u>AEP-Ohio</u>

- Conesville Unit 3 (165 MW) OH
- Kammer Units 1-3 (600 MW) WV
- Muskingum River Units 1 & 3 (395 MW) OH
- Muskingum River Units 2 & 4 (395 MW) OH
- Picway Unit 5 (95 MW) OH
- Sporn Units 2 & 4 (290 MW) WV
- Sporn Unit 5 (440 MW) WV

<u>KPCo</u>

- Big Sandy Unit 1 (278 MW) KY

Among this group of units are several that were impacted by the Consent Decree from the previously settled NSR litigation. These units, and the dates by which, according to the agreement, they must be retired, repowered (as highly thermally efficient combined cycle units), or retrofitted with FGD and SCR systems ("R/RR"), are:

- Conesville Unit 3, by December 31, 2012
- Sporn Unit 5, by December 31, 2013
- Muskingum River Units 1-4, by December 31, 2015
- A total of 600 MW from Sporn 1-4, Clinch River 1-3, Tanners Creek 1-3, or Kammer 1-3, by December 31, 2018.

Prior IRP cycle evaluations of unit conditions and related criteria laid the groundwork for purposes of determining a potential sequence of unit retirements for subsequent resource planning purposes. This sequencing also assumed a "staggered and extended" implementation of then-anticipated U.S. EPA rulemaking. Those dates typically had extended at least through this decade (12/2019).

However, with the new implementation dates contained in the recently issued CSAPR, as well as EGU MACT and CCR rules proposed in 2011, such sequencing now may not be achievable. All units will need to be controlled under the proposed EGU MACT rule by January 2015 (or, potentially, January 2016 should a one-year extension be granted for that purpose). This new rule may have established the retirement date for each uncontrolled unit, including Tanners Creek 1-3. Those units that would be able to operate with limited investment, such as I&M's Tanners Creek 4, will not be retired to comply with these rules.

5. Projected Capacity Position

Exhibits 5-3 and 5-4 present the I&M and AEP System-East Zone capacity positions with the specified retirements versus the projected PJM reserve margin requirement. The impact of any new non-contracted/announced capacity builds and market purchases are shown as "New Fossil Fuel Generation (MW)" and "Annual Purchases (MW)". The impact of additional Renewable Purchase Power Agreements (REPA) that would be required to minimally achieve mandated renewable energy (largely, wind) resources are shown as "New Renewable Generation (MW)". Based on the assumptions mentioned, the capacity of the AEP System-East Zone would move to a deficit position beginning in 2014 without these additions whereas I&M has sufficient capacity until Tanners Creek 4 retires in 2024.

D. Supply-Side Resource Screening (170 IAC 4-7-6(c) (1)-(2) and 170 IAC 4-7-7(a) and 170 IAC 4-7-8(4))

1. Capacity Resource Options

In addition to market capacity purchase options, new-build options were modeled to represent peaking, intermediate, and baseload capacity needs. To reduce the number of modeling permutations in *Strategist®*, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant. The options assumed to be available for modeling analyses for the AEP System-East Zone are presented in Exhibit 3 of the Confidential Supplement. It is also important to note that AEP's planning position for its East Zone is to take advantage of market opportunities when economical, both in the form of limited-term bilateral capacity purchases from non-affiliate sources and by way of available, discounted generation asset purchases. Such market opportunities could be utilized to hedge capacity planning exposures should they emerge and create (energy) option value to the Company. These opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

2. Supply-Side Screening

As identified in Exhibit 3 of the Confidential Supplement, numerous new-build generating technologies were considered to address this coming need to construct new capacity. However, in an attempt to reduce the problem size within the comprehensive *Strategist®* modeling application, an economic screening process was used to analyze various options and develop a quantitative comparison for each type of capacity (baseload, intermediate, and peaking) on a forty-year, levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed O&M, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

All peaking technology options, for example, were compared to find the relative economic "best of class" to be used for purposes of further modeling within *Strategist®*. Screening curves for the peaking capacity types are shown on Exhibit 5-5. This chart suggests that the GE 7EA and 7FA turbines are generally more economical than the various aero-derivative machines up to a capacity factor range of 15-20%. Similar screening results are presented for intermediate capacity in Exhibit 5-6 and baseload capacity in Exhibits 5-7 and 5-8. A comparison of the best-in-class technologies is presented in Exhibit 5-9.

The best of class technology determined by this screening process was taken forward to the *Strategist®* model. These generation technologies were intended to represent reasonable proxies for each capacity type (baseload, intermediate, peaking). Subsequent substitution of specific technologies could occur in any ultimate plan, based on emerging economic or non-economic factors not yet identified.

3. Coal Based Options

Pulverized Coal (PC) plants are the workhorse of the U.S. electric power generation industry. In a PC plant, the coal is ground into fine particles that are blown into a furnace where combustion takes place. The heat from the combustion of coal is used to generate steam to supply a steam turbine that drives a generator to produce electricity. Major by-products of combustion include SO_2, NO_X, CO_2, and ash, as well as various forms of elements in the coal ash including mercury (Hg). The ash byproduct is often used in concrete, paint, and plastic applications.

Steam cycle thermodynamics for the pulverized coal-fired units–which determines the efficiency of generating electricity– falls into one of two categories, subcritical or supercritical. Subcritical operating conditions are generally accepted to be at up to 2,400 psig/1,000°F superheated steam, with a single or double reheat systems to 1,000°F, while supercritical steam cycles typically operate at up to 3,600 psig, with 1,000°F -1,050°F main steam and reheat steam temperatures. AEP has recognized the benefits of the supercritical design for many years. All eighteen of the units in the AEP-East system built since 1964 have utilized the supercritical design, including APCo's Mountaineer Plant and Amos units 1, 2, and 3.

There have been advances in the supercritical design over the years, and there are now commercial units operating at or above 3,600 psig and >1,100°F steam temperatures, known as an ultra supercritical (USC) design. AEP's Turk plant, which is currently under construction in Arkansas, is a new USC design.

The overall efficiency of the supercritical design is higher than the subcritical design by approximately 4% and USC design efficiency is higher than a supercritical design by approximately 4 to 5%. Additionally, the new variable pressure ultra supercritical units are projected to have an overall efficiency improvement throughout the entire load range, not just at full load conditions.

Given the long time-horizons of most resource planning exercises, IRP processes must be able to consider new technologies such as Integrated Gasification Combined Cycle (IGCC). The assessment of such technologies is based on cost and performance estimates from commonly cited public sources, consortia where AEP is actively engaged, and vendor relationships, as well as AEP's own experience and expertise.

IGCC is of particular interest to AEP in light of the abundance, accessibility, and affordability of high rank coals for the company–particularly in its eastern zone. IGCC technology with carbon capture has the potential to achieve the environmental benefits closer to those of a natural gas-fired plant, and thermal performance closer to that of a combined cycle, yet with the low fuel cost associated with coal. The coal gasification process appears well-positioned for integration of ultimate carbon capture and storage technologies, which will be a critical measure in any future mitigation of greenhouse gas emissions associated with the generation of electricity. As an additional observation, the small number of IGCC equipment suppliers and few utility-scale facilities in commercial operations worldwide means a large share of technology and performance risk falls on owners, although the on-going collaboration with technology developers may mitigate some of this risk.

The IGCC process employs a gasifier in which coal is partially combusted with oxygen and steam to form what is commonly called "syngas"–a combination of carbon monoxide, methane, and hydrogen. The syngas produced by the gasifier then is cleaned to remove the particulate and sulfur compounds. Sulfur is converted to hydrogen sulfide and ash is converted into glassy slag. Mercury is removed in a bed of activated carbon. The syngas then is fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG), where it produces steam that drives a steam turbine as would a natural gas-fired combined cycle unit.

IGCC enjoys comparable thermal efficiencies to USC-PC. Its ability to utilize a wide variety of coals and other fuels positions it extremely well to address the challenges of maintaining an adequate baseload capability with efficient, low-emitting, low-variable cost generating technology. Further, IGCC is in a unique position to be pre-positioned for carbon capture as, unlike PC technologies, it has the ability to perform such capture on a "pre-combustion" basis. It is believed that this will ultimately lead to improved net thermal efficiency than would be required by PC technology utilizing post-combustion carbon capture technology.

Another baseload fossil-fueled option, a Circulating Fluidized Bed Combustion (CFB) plant, is similar to a PC plant except that the coal is crushed rather than pulverized, and the coal is combusted in a reaction chamber rather than the furnace of a PC boiler. A CFB boiler is capable of burning bituminous and sub-bituminous coal plus a wide range of fuels that cannot be accommodated by PC designs. These fuels include, coal waste, lignite, petroleum coke, a variety of waste fuels, and biomass. Units are sometimes designed to fire using several fuels, which emphasizes this technology's major advantage: fuel flexibility. Coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air blown in from below through a series of nozzles. CFB boilers operate at lower temperatures than pulverized coal-fired boilers. The energy conversion efficiency of CFB plants tends to be slightly lower than that of pulverized coal-fired counterparts of the same size and steam conditions because of higher excess air and auxiliary power requirements.

CFB boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_X formation, and capture SO_2 in situ. Specifically, SO_2 is captured during the combustion process by limestone being fed into the bed of hot particles that are fluidized by the combustion air blown in from below. The limestone is converted into free lime, which reacts with the SO_2. Historically, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. In July of 2009, the Lagisza Power Plant in Poland began commercial operations; the plant is the largest and first supercritical CFB in operation and is rated at 460 MW. AEP has no commercial operating experience with generation utilizing circulating fluidized bed boilers but is familiar with the technology through prior research, including the Tidd pressurized fluidized bed demonstration project. Commercial CFB units utilize a subcritical steam cycle, resulting in a lower thermal efficiency.

4. Nuclear

Although new reactor designs and ongoing improvements in safety systems make nuclear power an increasingly viable option as a new-build alternative due to it being an emission-free power source, concerns about public acceptance/permitting (especially since the recent disaster in Japan), spent nuclear fuel storage, lead-time, high capital costs, and the risk of cost overruns continue to temper its consideration. For these reasons, among others, AEP does not currently view new nuclear capability as a viable option to meet the capacity resource needs of AEP System-East Zone within this forecast period (2012-2031). However, both the economic and political viability of nuclear power and energy will continue to be explored given:

- I&M and AEP-East zone's ultimate need for baseload capacity;
- the cost and performance uncertainty surrounding the advancement and commercialization of clean coal technology, notably, IGCC;
- the cost and performance uncertainty of carbon capture and storage technology;
- the continued push to address AEP's carbon footprint and the mitigating impact additional nuclear power clearly would have in that regard; and
- the prospect of a federal Clean Energy Standard that would effectively embrace the introduction of nuclear generation.

Growth in U.S. nuclear generation since 1977 has been primarily achieved through "uprating" – the practice of increasing capacity at an existing nuclear power plant. As of January 2010, the NRC had approved 124 uprates totaling 5,726 MW of capacity. That amount is equivalent to adding another five-to-six conventional-sized nuclear reactors to the electricity supply portfolio.

5. Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a heat recovery steam generator (HRSG) producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while one of the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-60% Low Heating Value), low emission levels, small footprint, and shorter construction period than coal-based plants. In the past 8 to 10 years NGCC plants were often selected to meet new intermediate and certain baseload needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration ("black start") services. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

6. Simple Cycle Combustion Turbines (NGCT)

In “industrial” or “frame-type” combustion turbine systems, air compressed by an axial compressor (front section) is mixed with fuel and burned in a combustion chamber (middle section). The resulting hot gas then expands and cools while passing through a turbine (rear section). The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A simple cycle combustion turbine system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost i.e., not recovered as in a combined cycle design. While not as efficient (at 30-35% LHV), they are, however, inexpensive to purchase, compact, and simple to operate.

7. Aeroderivatives (AD)

Aeroderivatives are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7EA frame machine requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is on the order of 20% higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. The aeroderivatives can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide aeroderivatives the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: a) the penetration of variable renewables increase; b) baseload generation processes become more complex limiting their ability to load follow and; c) intermediate coal-fueled generating units are retired from commercial service.

Aeroderivatives weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an aeroderivative over an industrial turbine. Aeroderivatives in the less than 100 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in the aeroderivative units.

Some of the better known aeroderivative vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.

8. Wind

Wind is currently the fastest growing form of electricity generation in the world. Utility wind energy is generated by wind turbines with a range 1.0-to-2.5 MW, with a 1.5 MW turbine being the most common size used in commercial applications today with over 40,000 MW of wind online in the United States as of February 2011. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical from the perspective of both the existing wind resource and its proximity to a transmission system with available capacity.

Ultimately, as turbine production increases to match the significant increase in demand, the high capital costs of wind generation should begin to decline. Currently, the cost of electricity from wind generation is becoming competitive within AEP-East due largely, however, to subsidies, such as the federal production tax credit as well as consideration given to REC values, anticipated rising fuel costs or future carbon costs.

A drawback of wind is that it represents a variable source of power in most non-coastal locales, with capacity factors ranging from 30 to 45 percent; thus its life-cycle cost ($/MWh), excluding subsidies, is typically higher than the marginal (avoided) cost of energy, in spite of wind's zero dollar fuel cost. Another obstacle with wind power is that its most critical factors (i.e., wind speed and sustainability) are typically highest in very remote locations, and this forces the electricity to be transmitted long distances to load centers necessitating the buildout of EHV transmission to optimally integrate large additions of wind into the grid.

9. Solar

Solar power takes a couple of viable forms to produce electricity: concentrating and photovoltaics. Concentrating solar – which heats a working fluid to temperatures sufficient to power a turbine - produces electricity on a large scale (100 MW) and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (2 kW to 20 MW per installation) and are distributed throughout the grid. In AEP-East, solar has applications as both large scale and distributed generation. The appeal of solar is broad and recent legislation in Ohio has made its pursuit mandatory subject to rate impacts, beginning in 2009. Solar photovoltaics are represented in this IRP based on this solar requirement being met in

Ohio. However, the amounts of solar prescribed in the law, while substantial, will not have a significant effect on the timing or amount of other supply assets within a twenty-year forecast period.

6) ENVIRONMENTAL COMPLIANCE

6. Environmental Compliance

A. Introduction

In support of requirements found in **170 IAC 4.7.4(8), 170 IAC 4.7.6(a)(4), 170 IAC 4.7.6(c)(2)-(3), 170 IAC 4.7.8(5), and 170 IAC 4.7.8(9)**, the following information provides background on both current and future environmental regulatory compliance plan issues with the AEP system. AEP's goal in the development of the integrated resource and compliance plan is to develop a comprehensive plan that not only allows AEP and I&M to meet the future resource needs of the Company in a reliable manner, but also to meet increasingly more stringent environmental requirements in a cost effective manner.

B. Solid Waste Disposal 170 IAC 4-7-6(a)(4)(B)

Rockport has an aggressive pollution prevention plan for solid waste generated. coal combustion by-products (CCBs), comprised of bottom ash captured in the boiler and fly ash captured in the electrostatic precipitator (ESP), which totaled approximately 539,702 tons of material in 2010. Prior to 2010, fly ash was produced and marketed for reuse in applications that include flowable fill, ready mix concrete, raw feed for cement manufacture, and structural fills. Fly ash sales ceased beginning in 2010 because the activated carbon injection system (ACI) to control mercury was placed into service. Ash sales could potentially resume in the future if cost-effective methods are developed to lessen the effect of activated carbon on the fly ash properties for reuse. Fly ash is disposed of at the on-site landfill permitted by the Indiana Department of Environmental Management (IDEM). The landfill is underlain with clay, has a groundwater monitoring well system that is sampled to understand any releases to the groundwater, and storm-water runoff collection and treatment system, with discharge regulated by an IDEM-issued National Pollutant Discharge Elimination System (NPDES) permit. Unused bottom ash is stored for future use in a pond also regulated by an IDEM NPDES permit.

Tanners Creek uses a wet system for all ash handling. Fly ash from all units is sluiced to a fly ash pond southeast of the plant. The pond is underlain with a 20-mil PVC liner and is equipped with ground-water monitoring wells. Bottom ash from Units 1-3 is sluiced to the auxiliary ash pond. Unit 4 boiler slag is sluiced to a reclaim pond adjacent to that unit. Boiler slag is excavated and utilized on a regular basis by an on-site sales contractor. In 2010, CCBs comprised of fly ash, bottom ash, and boiler slag, generated at the plant totaled about 152,881 tons. Effluent from the fly ash, auxiliary, and reclaim ponds is routed to the main ash pond for further treatment prior to discharge to the Ohio River in accordance with the plant's NPDES permit. The landfill at Tanners Creek was recently expanded, with the intention of allowing the landfill to continue accepting CCBs at Tanners Creek for another 10 years.

The US Environmental Protection Agency (EPA) is also reviewing the current rules regarding the treatment of CCBs, which may affect handling and disposal of CCBs in the future. The EPA issued a proposed Coal Combustion Residuals Rule (CCR) in June 2010 and a final rule is expected to be available by the end of 2012. Discussion of this rule is available in more detail in part L of this section of the IRP.

Non-hazardous solid wastes from Rockport and Tanners Creek are disposed at permitted municipal solid waste landfills. Numerous non-hazardous and hazardous wastes are recycled, including everything from paper and cardboard to batteries and used mercury.

Typical solid wastes for hydros include trash, solvents, and hydraulic fluid, which are recycled or properly disposed using licensed vendors.

C. Hazardous Waste Disposal 170 IAC 4-7-6(a)(4)(C) and (D)

Rockport is typically a small-quantity generator of hazardous waste, such as parts washer by-products, batteries, light bulbs, and paints. The plant recycles light bulbs and batteries. Rockport has significantly reduced the amount of solvents generated in the parts washers by purchasing its own equipment and processing its own non-hazardous solvents.

Tanners Creek is typically a conditionally exempt small quantity generator of hazardous wastes, including paints and paint-related waste, mercury waste, light bulbs, batteries, and excess/outdated chemicals. The plant recycles light bulbs, batteries and mercury waste.

For the hydro facilities, hazardous waste is transferred to the Twin Branch hydro in Mishawaka, Indiana and stored until disposal by a licensed hazardous waste contractor. Normal variation in monthly waste generation alternates the facility's status between conditionally exempt (typically) to small quantity generator (occasionally). Universal wastes such as lighting and batteries are disposed by third-party vendors from the facilities.

D. Air Emissions 170 IAC 4-7-6(a)(4)(A)

There are numerous air regulations that have been promulgated or that are under development, which will apply to I&M facilities, specifically the coal-fired Tanners Creek and Rockport plants. Currently, air emissions from both plants are regulated by Title V operating permits that incorporate the requirements of the Clean Air Act (CAA) and the Indiana State Implementation Plan (SIP). Other applicable requirements include those related to the CSAPR and the NSR Consent Decree. Several air regulatory programs are under development and will apply to both Rockport and Tanners Creek plants, including those related to the regulation of hazardous air pollutants (HAPS) and greenhouse gases (GHG).

Potential air emissions at the Rockport Plant are reduced through the use of electrostatic precipitators (ESPs), low sulfur coal, low NO_x burners and over-fire air (OFA), as well as a dry fly-ash handling system. An activated carbon injection system to reduce mercury emissions at the Rockport, as approved in IURC Cause No. 43636 is also installed. Tanners Creek controls air emissions through the use of ESPs, low sulfur coals, low NO_X combustion systems, and a wet fly-ash handling system. Also, as approved in IURC Cause No. 43636, selective non-catalytic reduction (SNCR) systems at Tanner's Creek Units 1-3 are used to reduce NO_x emissions.

I&M is a party to the Interim Allowance Agreement, Modification 1, effective 1996. Through this agreement, I&M jointly purchases SO_2 allowances procured for the AEP System-East Zone's (AEP-East) compliance. Additionally, any SO_2 allowance excesses or shortages are sold or purchased to the other parties to the agreement if needed.

Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_x). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions. For these reasons, the IAA will likely be terminated, as described in Section 1.

E. Environmental Compliance Programs 170 IAC 4.7.4(8)

1. Title IV Acid Rain Program

The Title IV Acid Rain Program rules were developed in response to the Clean Air Act Amendments (CAAA) of 1990 and required state environmental agencies to promulgate rules implementing the Federal program. The Indiana State Title IV program was established by incorporating federal acid rain regulations by reference in Indiana Administrative Code 326 IAC 21, which created calendar year based compliance programs for reducing sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

The acid rain NO_x reduction program was also implemented using a two-phase approach, with the first phase becoming effective in 1996 and the second phase in 2000. Under the NO_x reduction program, the acid rain rules established annual NO_x rates that varied depending on boiler-type. However, the rules allowed companies to comply with the Title IV NO_x standards by using system wide averaging plans. Rockport employed the combined use of low NO_x burners and sub-bituminous coal to reduce NO_x emissions, while low NO_x burners were installed at Tanners Creek boilers in response to the Title IV NO_x program.

2. Indiana NO_x Budget Program State Implementation Plan (SIP) Call

In addition to the Title IV NO_x reduction program, the Indiana NO_x Budget Program State Implementation Plan (SIP) Call was designed to reduce the interstate transport of NOx emissions that were determined to significantly impact downwind ozone concentrations. For those states opting to meet the obligations of the NO_x SIP call through a cap and trade program, EPA included a model NO_x Budget Trading Program rule (40 CFR 96), which was developed to facilitate cost effective emissions reductions of NO_x from large stationary sources. The NO_x SIP Call rules generally required electric generating units (EGUs) to reduce NO_x emissions to a level roughly equivalent to a 0.15-lb/MMBtu emission rate, applicable during the ozone season that runs from May 1st through September 30th each year. The initial compliance deadline for the NO_x SIP Call emission reductions was May 31, 2004. The SIP Call utilized an emissions allowance system that allowed AEP and I&M to comply with the rates by the most cost-effective method, which was either to install control technology, purchase allowances, or a mix of both.

Planning for the NO_x SIP Call allowances and emissions was performed for I&M and AEP-East utilizing the IRP process, review of emissions and control effectiveness, allowance availability, NO_x market prices and proposed regulatory changes. Projected emissions, including any future changes to the NO_x reduction effectiveness, were compared to the available allowance inventory including any potential effects of progressive flow control and projected inventory to determine the amount of allowances that were required to ensure compliance. Flow control provisions were included in the NO_x SIP Call to discourage extensive use of banked allowances in a particular ozone season. Flow control was triggered if the total number of banked allowances from all sources exceeded 10 percent of the region-wide NO_x emissions budget. Beginning in 2009 with the commencement of CAIR, the NO_x Budget SIP Call Program and progressive flow control ended.

3. Clean Air Interstate Rule (CAIR)

On March 10, 2005, the EPA announced the CAIR, which called for significant reduction of SO_2 and NO_x from EGUs. The CAIR program incorporated three cap-and-trade programs: an ozone season NO_x reduction program that replaced the NO_x SIP Call program, an annual NO_x reduction program, and an annual SO_2 reduction program that was administered through the Title IV Acid Rain Program. In order for I&M to have maintained sufficient allowances to be compliant with the CAIR, it was planned on being necessary to purchase a significant number of allowances on an annual basis.

On July 11th, 2008, the District of Columbia Circuit Court of Appeals issued a ruling vacating the CAIR and remanding the rule back to the EPA for revision. However, on December 23, 2008, the Court indicated in a second ruling that the CAIR was being remanded to EPA for revision and was not being vacated. Planning for compliance at this time for CAIR was necessary, but the company was mindful that more stringent and restrictive emission policies would likely be the result of the revision.

4. New Source Review Settlement

On October 9, 2007 AEP entered into a consent decree with the Department of Justice to settle all complaints filed against AEP and its affiliates of which I&M is included. I&M is bound by this decree to retrofit an SCR and FGD on Rockport Units 1 and 2 by December 31, 2017 and December 31, 2019, respectively. In addition, it was agreed that Tanners Creek Units 1-3 and Tanners Creek 4 would only burn coal with sulfur content no greater than 1.2 lb/mm Btu on an average annual basis. These fuel restrictions are consistent with the current coal supply at these units.

The NSR Consent Decree also contains annual NO_x and SO_2 caps for the AEP operated coal units for AEP-East, of which I&M is a part. These annual caps are displayed in Figure 6-1 and 6-2.

NSR Consent Decree Annual NO_x Cap

Calendar Year	Annual Tonnage Limitations for NO_x
2009	96,000
2010	92,500
2011	92,500
2012	85,000
2013	85,000
2014	85,000
2015	75,000
2016, and each year thereafter	72,000

Figure 6-1 New Source Review (NSR) Consent Decree Annual NO_x Caps

NSR Consent Decree Annual SO_2 Cap

Calendar Year	Annual Tonnage Limitations for SO_2
2010	450,000
2011	450,000
2012	420,000
2013	350,000
2014	340,000
2015	275,000
2016	260,000
2017	235,000
2018	184,000
2019, and each year thereafter	174,000

Figure 6-2 New Source Review (NSR) Consent Decree Annual SO_2 Caps

While the Tanners Creek Plant was not required to install specific pollution control technologies, the NSR Consent Decree Annual NO_x cap was the driving factor in the retrofit of Tanners Creek Units 1-3 with SNCR technology.

5. Cross State Air Pollution Rule (CSAPR)

The EPA proposed and published a replacement for the Clean Air Interstate Rule (CAIR) in the form of the Clean Air Transport Rule (CATR) on August 2, 2010 and finalized that rule on July 7, 2011 as the CSAPR. The CSAPR is more stringent in its final form than as the CATR and CAIR.

Twenty-eight (28) states are covered by the new rule. All states in which AEP owns and/or operates power plants are included in at least one of the CSAPR programs. Indiana, Kentucky, Michigan, Ohio, Texas, Virginia and West Virginia fall under all the programs regulating annual SO_2, and both annual and seasonal NO_x. Arkansas, Louisiana and Oklahoma fall under the CSAPR seasonal NO_x program only.

CSAPR has an initial compliance phase deadline for the SO_2 and NO_X programs beginning on January 1, 2012 ("Phase 1"). A second, more stringent compliance phase for SO_2 emissions limits (only) will take effect beginning on January 1, 2014 ("Phase 2"). Prescribed Annual and Seasonal NO_x emission limits, however, will remain approximately at "Phase 1" levels in 2014. Figure 6-3 displays the unit specific allocations to impact I&M generating facilities under each phase.

In October 2011, the Federal EPA released a supplemental proposed rule revising portions of the final CSAPR. The proposed rule would correct errors in unit-specific assumptions and make available additional allowances in ten states, including Louisiana and Texas, and provide additional allowances for the new unit set aside in Arkansas. In addition, the proposed rule would amend the allowance trading assurance provisions which restrict interstate trading of allowances, making them effective January 1, 2014 instead of January 1, 2012.

CSAPR SO_2 and NO_x Allowances Allocated to Indiana Michigan Power Company[5]

	SO_2		Annual NO_x		Ozone Season NO_x	
	2012	**2014**	**2012**	**2014**	**2012**	**2014**
Rockport Unit 1	21,292	11,776	7,883	7,788	3,316	3,265
Rockport Unit 2	19,923	11,019	7,376	7,288	3,148	3,100
Tanners Creek Unit 1	1,980	1,095	733	724	295	290
Tanners Creek Unit 2	1,920	1,062	711	702	311	307
Tanners Creek Unit 3	2,634	1,457	975	963	424	418
Tanners Creek Unit 4	5,819	3,219	2,154	2,129	1,058	1,042

Figure 6-3 Cross State Air Pollution Rule (CSAPR) Allocated I&M CSAPR SO_2 and NO_x Allowances

F. Future Environmental Rules

Several environmental regulations have been proposed that will apply to the electricity generating sector once finalized. The following is not meant to be comprehensive, but lists some of the major issues that will need to be addressed over the forecast period.

1. Coal Combustion Residuals (CCR) Rule

The EPA proposed this rule in June 2010, with a final rulemaking anticipated in late 2012, to address the management of residual byproducts from the combustion of coal in power plants (coal ash) and captured by emission control technologies. The proposed rule includes specific design and monitoring standards for new and existing landfills and surface impoundments, as well as measures to ensure and maintain the structural integrity of surface impoundment/ponds. The proposed CCR rulemaking may require the conversion of most "wet" ash impoundments to "dry" ash landfills, the relining or closing

[5] Note: On Oct. 6, 2010 EPA announced proposed revisions to CSAPR that would result in slight modifications to the SO_2 and NO_X budgets. These revisions have not been finalized and are not included in the table above.

of any remaining ash impoundment ponds, and the construction of additional waste water treatment facilities by approximately January 1, 2018. Even if these residual materials are categorized as "Subtitle D," or non-hazardous materials[6]—each and every coal unit in the AEP fleet, including all APCo coal facilities, would require plant modifications and capital expenditures to address CCR requirements.

2. EGU MACT Rule

To replace the federal court vacated Clean Air Mercury Rule (CAMR), the EPA proposed a rule in March 2011 designed to reduce and regulate emissions of mercury and other toxic metals and acid gases at electric generating units by using maximum achievable control technology (EGU MACT) emission standards. The Clean Air Act (CAA) requires compliance within 3 years after the issuance of this final rulemaking, which in this case, would be at approximately the end of 2014, but also provides a one year extension which could potentially delay implementation to the end of 2015 if specific criteria are satisfied. The proposed EGU MACT emission limits will require the installation of emission control equipment, such as flue gas desulfurization (FGD) selective catalytic reduction (SCR) technology, dry sorbent injection (DSI), and activated carbon injection (ACI) on coal-fired utility units, as well as the performance of upgrades to some existing emission control systems in order to achieve the required emission rates. EPA is expected to finalize the rule by December 16, 2011.

In anticipation of these requirements, AEP and I&M successfully tested the ability of activated carbon injection (ACI) to mitigate mercury emissions at the Rockport plant

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[6] As set forth under the current Resource Conservation and Recovery Act (RCRA)

in the spring of 2006. In February of 2009, after already having had incurred a significant portion of the capital investment, I&M filed for a Certificate of Public Convenience and Necessity (CPCN) for cost recovery of a permanent ACI system to be installed at the Rockport Plant. The CPCN was granted by the IURC in Cause No. 43636 in July of 2009.

3. Clean Water Act "316(b)" Rule

A proposed rule for the Clean Water Act 316(b) was issued by the EPA on March 28, 2011 and final rulemaking is expected mid-2012. The proposed rule prescribes technology standards for cooling water intake structures that would decrease interference with fish and other aquatic organisms. Given that I&M's Rockport units are already equipped with natural draft, hyperbolic cooling towers, the most significant potential impact of the proposed rule would be the need to install additional fish screening at the front of the water intake structure. As proposed, compliance requirements for the Tanners Creek units and DC Cook Nuclear Plant would to be determined based on a site-specific study. The implementation schedule for this rule could extend late into this decade due to the site specific nature of the permitting process.

4. Greenhouse Gas (GHG) Regulations

For many years, the potential for requirements to reduce GHG gas emissions, including carbon dioxide (CO_2), has been one of the most significant sustainability issues facing APCo and AEP. AEP and I&M have relied on coal for a number of reasons: coal provides an affordable, reliable, and sustainable source of energy; AEP and I&M are located in close proximity to the nation's coal supply; AEP and I&M have a legacy in coal-fired generation as demonstrated by the huge investments made and the engineering and operational expertise developed over more than a century. As a result, coal is expected to remain a key part of AEP's fuel portfolio for many years to come. AEP is one of the largest consumers of coal in the Western Hemisphere and coal currently accounts is the major portion of the generation portfolio.

AEP supports a legislative approach to resolve the GHG issue rather than a regulatory approach. Without a regulatory driver, an investment to develop GHG control technologies is too significant to justify the capital cost and risk. Given that there are currently no cost-effective post combustion control technologies or best achievable retrofit technology (BART) available for GHG emissions, future standards are anticipated to focus on energy efficiency opportunities. Such GHG legislation from Congress is not expected in the next few years.

G. I&M Environmental Compliance

This 2011 IRP considered final and proposed EPA regulations. In addition, the IRP development process assumed there will be future legislation to control GHG/CO_2 emissions which would become effective at some point in the 2022 timeframe. Emission compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. Moreover, the cumulative cost of complying with these rules will ultimately have an impact on proposed retirement dates of existing coal-fueled units that would otherwise be forced to install emission control equipment.

Major near-term challenges relate to the development and implementation of a new compliance plan to comply with stringent implementation time periods for CSAPR (beginning January 2012) and for the EGU MACT rule (expected beginning January

2015). For instance, AEP has engineered and constructed nine FGD systems over the past decade. This experience indicates that approximately 52-56 months is required to permit, design and engineer, construct and commission such a system. This timeframe approaches five years or more when also considering any up-front regulatory (*i.e.*, "need") approvals required.

Also complicating the lack of flexibility on compliance timeframes is the fact that EPA established more stringent SO_2 and NO_x state (emission) allowance budgets in the final CSAPR than it proposed in August 2010. AEP and I&M have evaluated possible emission mitigation strategies for complying with CSAPR, including including:

- low-cost and quick-to-install environmental retrofits options;
- fuel switching options (to lower sulfur-content coals and repowering to natural gas); and
- dispatch optimization options (including the possibility of unit generation curtailments)

Any historical allowances from CAIR will expire at the end of 2011, and be replaced by the allowance market created under the CSAPR. If it is economical and the market supply is available, I&M will purchase allowances for emissions above their allocations under CSAPR.

I&M is currently obligated by the NSR Consent Decree to install SO_2 and NO_x controls at Rockport Unit 1 by the end of 2017 and at Rockport Unit 2 by the end of 2019. The CSAPR and EGU MACT Rule will accelerate that requirement significantly. I&M analysis of the EPA's final CSAPR indicates that, at a minimum, one unit at the Rockport Plant will be required to have an FGD installed by January 1, 2012 to avoid having to curtail generation. Under the proposed EGU MACT, I&M would be required to install additional environmental controls at the Rockport Plant by January 1, 2015 or one year later if the EPA grants a compliance extension. The short compliance deadline required by the proposed EGU MACT Rule is clearly a challenge for implementing additional emission control retrofit projects at Rockport in a timely manner.

On August 1, 2011, I&M filed in Cause No. 44033 a request for a Certificate of Public Need and Necessity indicating that the best course for I&M customers and for I&M compliance is to install a FGD and SCR at one of the Rockport units. It is also indicated that it will be necessary to significantly curtail operations at the Rockport and Tanners Creek facilities to limit emissions for compliance with the CSAPR until environmental controls can be installed. In addition to the environmental projects at Rockport, the retirements of Tanners Creek units 1 through 3 will accelerate to December 31, 2014.

In summary, AEP has conducted a series of reviews to evaluate the cost effectiveness of its air emissions control strategy in complying with existing and anticipated environmental regulations. The economic analyses performed indicate that an FGD and SCR at one of the Rockport units, as well as the accelerated retirement of Tanners Creek Units 1 through 3, are part of a least cost compliance plan. AEP is actively undertaking implementation of this compliance plan for I&M to meet proposed and final EPA regulations.

H. Rockport and Tanners Creek Air Emissions

In accordance with requirements found in **170 IAC 4-7-6(a)(4)(A)**, projections of SO_2, NO_X, mercury, and CO_2 emissions are provided in Exhibit 2 of the Confidential Supplement.

7) ELECTRIC TRANSMISSION FORECAST

7. Electric Transmission Forecast

A. General Description (170 IAC 4-7-4(12))

The eastern Transmission System (eastern zone) consists of the transmission facilities of the seven eastern AEP operating companies. This portion of the Transmission System is composed of approximately 15,000 miles of circuitry operating at or above 100 kV. The eastern zone includes over 2,100 miles of 765 kV overlaying 3,800 miles of 345 kV and over 8,800 miles of 138 kV circuitry. This expansive system allows AEP to economically and reliably deliver electric power to approximately 24,200 MW of customer demand connected to the eastern Transmission System that takes transmission service under the PJM open access transmission tariff.

The eastern Transmission System is the most integrated transmission system in the Eastern Interconnection. These interconnections provide an electric pathway to facilitate access to off-system resources and serve as a delivery mechanism to adjacent companies. The entire eastern Transmission System is located within the Reliability*First* (RFC) Regional Entity. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization, and now participates in the PJM markets.

As a result of the eastern Transmission System's geographical location and expanse as well as its numerous interconnections, the eastern Transmission System can be influenced by both internal and external factors. Facility outages, load changes, or generation redispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the eastern Transmission System is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern Transmission System conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

AEP's eastern Transmission System assets are aging. Therefore, in order to maintain reliability, significant investments will have to be made over the next ten years.

Despite the robust nature of the eastern Transmission System, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant transmission enhancement to the eastern AEP Transmission System over the last few years was completed in 2006. This was the construction of a 90-mile 765 kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, EHV/138 kV transformer capacity has been increased at various stations across the eastern Transmission System.

Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern Transmission System. Currently, there is more than 26,000 MW of AEP System-East generation and approximately 6,000 MW of additional merchant generation connected to the eastern Transmission System. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for approximately 1,000 MW of additional generation to be connected to the eastern Transmission System over the next several years. There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern

Transmission System required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and Midwest ISO markets.

The retirement of Conesville units 1 and 2 in 2006 and the anticipated retirement of Conesville Unit 3 in 2012 will result in the need for power to be transmitted over a longer distance into the Columbus, Ohio metro area. In addition, these retirements will result in the loss of dynamic voltage regulation. Since there is very little baseload generation in central Ohio, these retirements could be significant. The retirement of these units could require the addition of dynamic reactive compensation such as a Static VAR Compensator (SVC) device within the Columbus metro area. Within the eastern Transmission System, there are two areas in particular that could require significant transmission enhancements to allow the reliable integration of large generation facilities:

- Southern Indiana—there are limited transmission facilities in southern Indiana relative to the AEP generation resources, and generation resources of others in the area. Significant generation additions to AEP's transmission facilities (or connection to neighbor's facilities) will likely require significant transmission enhancements, including Extra-High Voltage (EHV) line construction, to address thermal and stability constraints. The Joint Venture Pioneer Project would address many of these concerns.

- Megawatt Valley—the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations during multiple transmission outages. Multiple overlapping transmission outages will require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Significant generation resource additions in the

Gavin/Amos/Mountaineer/Flatlick area will also influence these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers– to more fully integrate the transmission facilities in this generation-rich area. Thermal constraints will also need to be addressed.

Furthermore, even in areas where the transmission system is robust, care must be taken in siting large new generating plants in order to avoid local transmission loading problems and excessive fault duty levels.

The transmission line circuit miles in Indiana include approximately 600 miles of 765 kV, 1,380 miles of 345 kV, and 1,430 miles of 138 kV lines, as well as over 400 miles of 69 kV and approximately 600 miles of 34.5 kV lines. Confidential Exhibit 7 displays a map of the entire AEP System-East Zone transmission grid, including I&M.

B. Transmission Planning Process (170 IAC 4-7-4(10), (11), (13); 4-7-6(d) (2) and 170 IAC 4-7-4(13))

AEP and PJM coordinate the planning of the transmission facilities in the AEP System-East Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement (OA). By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, assuring a consistent view of needs and expansion timing while minimizing expenditures. When the RTEP identifies system upgrade requirements, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region while blending the local expertise of the transmission owners such as AEP with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria is consistent with NERC and Reliability*First* reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 (Confidential Exhibit 4) and these planning criteria are posted on the AEP website.[7] Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address the anticipated deficiency.

PJM also coordinates its regional expansion plan on behalf of the member utilities with the neighboring utilities and/or RTOs, including the Midwest ISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the Midwest ISO provides for joint transmission planning.

C. System-Wide Reliability Measure (170 IAC 4-7-4 (15); 4-7-6(a) (6) (B) and (C); 4-7-6(d) (2))

At the present time, there is no single measure of system-wide reliability that covers the entire system (transmission, distribution, and generation). However, in

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[7]http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/2011%20AEP%20PJM%20FERC%20715_Final_Part%204.pdf

practice, transmission reliability studies are conducted routinely for seasonal, near term, and long-term horizons to assess the anticipated performance of the transmission system. The reliability impact of resource adequacy (either supply or demand side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified.

D. Evaluation of Adequacy for Load Growth (170 IAC 4-7-4(14); 4-7-6(a) (6) (A-C); 4-7-6(d) (1))

As part of the on-going near-term/long-term planning process, AEP uses the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, AEP seeks solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads with a high degree of reliability.

E. Evaluation of Other Factors (170 IAC 4-7-4(14); 4-7-6(a) (6) (A-C); 4-7-6(d) (1))

As a member of PJM, and in compliance with the FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in AEP's eastern transmission system to support the power supply and transmission reliability needs of the entire PJM – Midwest ISO joint market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP currently has 40 active queue positions within Indiana totaling approximately 9,800 MW (nameplate), including projects that are either in various stages of study (28 projects), under construction (4 projects), or in-service (8 projects). Of these 40 active queue positions, 34 are wind generation requests. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of this planned generation that will actually come to fruition is unknown at this time.

F. Transmission Expansion Plans (170 IAC 4-7-6(a) (6) (A); 4-7-6(d) (1))

The transmission system expansion plans for the AEP System-East Zone are developed to meet projected future requirements. AEP uses power flow analyses to simulate normal conditions, and credible single and double contingencies to determine the potential thermal and voltage impact on the AEP transmission system in meeting the future requirements.

As discussed earlier, AEP will continue to develop transmission reinforcements to serve its own load areas, in coordination with PJM, to ensure compatibility, reliability and cost efficiency.

G. Transmission Project Descriptions (170 IAC 4-7-6(d) (3) and (4))

A detailed list and discussion of the AEP transmission projects that have recently been completed or presently underway in Indiana can be found under Chapter 7(I) (Indiana Transmission Projects) of this report. In addition, several other projects beyond the I&M area have also been completed or are underway across the AEP System-East Zone. While they do not directly impact I&M, such additions contribute to the robust health and capacity of the overall transmission grid, which also benefit Indiana customers.

AEP's transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M customers within the State of Indiana. AEP anticipates that incremental transmission expansion will continue to provide for expected load growth.

H. FERC Form 715 Information

A discussion of the eastern AEP System reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's FERC Form 715 Annual Transmission Planning and Evaluation Report, 2011 filing. That filing also provides transmission maps, and pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern transmission system. Pertinent excerpts from this report to meet the 170 IAC requirements are contained in Exhibit 4 of the Confidential Supplement.

I. Indiana Transmission Projects (170 IAC 4-7-6(d)(3) and (4))

A brief summary of the transmission projects in I&M's Indiana service territory for the 2011-2015 time frame is provided below. Project information includes the project name, a brief description of the project scope, projected in-service date, and projected cash flows[8] by year for each project.

- Mishawaka Area Improvements: Several 138 kV and 34.5 kV line overloads in the Elkhart area were identified by both PJM and AEP due to an outage of East Elkhart 345/138 kV transformer. Construction of a new 15 mile Twin Branch – East Elkhart 138 kV circuit using the vacant side of the existing tower line and developing a new 138/34.5 kV Station, Capital Avenue, to interconnect the existing 34.5 kV network will help alleviate these conditions. As part of the proposal, the distribution load will also be consolidated at the new 138/34.5 kV Capital Avenue station and the existing Currant Road station will be retired.

  2011: $0.5 million

  2012: $18.9 million

  2013: $14.4 million

  2014: $1.9 million

- South Side and South Bend Upgrades: PJM identified overloads on the Twin Branch – South Bend 138 kV line and the Jackson Road – South Side 138 kV line. To alleviate these overloads, AEP will replace terminal equipment at South Side and South Bend stations and perform a sag study on the Twin Branch – South Bend 138 kV line and the Jackson Road – South Side 138 kV line to improve the summer emergency rating of both lines.

  2012: $0.04 million

  2013: $0.04 million

- Lincoln Breaker Upgrade: PJM identified the Lincoln 138 kV breaker D as being over dutied and over loaded under certain contingency conditions. AEP is proposing to replace Lincoln 138 kV breaker D, the risers and cross bus sections of the Lincoln – Allen 138 kV circuit at Lincoln station.

  2012: $0.5 million

- Industrial Park – McKinley Upgrades: PJM identified an overload on the McKinley – Industrial Park 138 kV circuit. The proposed solution is to replace risers at McKinley and Industrial Park 138 kV stations and perform a sag study on the McKinley – Industrial Park 138 kV line. This will help improve the emergency rating of the 138 kV line to deal with contingency situations in the area.

  2012: $75,000

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[8] Please note that cash flows are approximated.

2013: $75,000

- <u>Northern Fort Wayne Improvements</u>: PJM and AEP identified overloads on the Auburn – Dekalb 138 kV circuit for loss of two 138 kV sources into the Northern Fort Wayne area. AEP has also demonstrated that several contingencies in the area can cause severe thermal overload and voltage conditions and a possible blackout in Northern Fort Wayne jeopardizing the bulk electric system (BES) in Indiana. To mitigate this potential situation, AEP will establish two new stations; a 138/69 kV station located near Auburn, Indiana and a 138 kV switching station near Huntertown, Indiana. The new station near Huntertown, Indiana will be connected to existing 138 kV lines from Robison Park and will thus serve as a source. A new double circuit line will be constructed from this station to the new 138/69 kV station and eventually to Auburn 138 kV station to provide an additional source for Northern Fort Wayne area.

  2012: $2.0 million

  2013: $10.0 million

  2014: $15.0 million

  2015: $5.0 million

- <u>Southern Indiana Improvements</u>: AEP is noticing a change in the flow patterns in the southern Indiana area. The 765 kV outlets were not originally designed for the flow pattern of heavy west to east flows. The root cause of this change in flow patter is the addition of over 25GW of generation around southern Indiana, southern Illinois and western Kentucky since 1989. Also, since the transmission facilities sit at the seams of Midwest ISO and PJM, high voltages are experience on the 345 kV network. The proposed improvements including the change in shunt reactor size at Rockport and transposition of 765 kV lines will help mitigate these constraints.

  2011: $7.7 million

  2012: $29.3 million

  2013: $3.5 million

- <u>Ball State University Load Increase</u>: Ball State University is increasing its load to accommodate a geothermal project on campus and conversion to 12 kV service. To serve this load, AEP is rebuilding the Tillotson 34.5 kV station and replacing the underground cables that feed Ball State's Christy Woods station. This will allow for future load growth and replaces an old, deteriorating station.

  2012: $2.5 million

  2013: $2.0 million

- Local Sag Studies: PJM identified overloads on several 138 kV lines that require sag and structure analysis to increase the emergency operating temperature of these lines. The lines being studied include:
  - Delaware – Madison 138 kV,
  - Desoto – Deer Creek 138 kV,
  - Desoto – Madison 138 kV,
  - Sorenson – Keystone 345 kV,
  - Sorenson – McKinley 138 kV,
  - Sorenson – Industrial Park 138 kV,
  - Huntington Junction – Sorenson 138 kV,
  - Albion – Robison Park 138 kV,
  - Harper – Hacienda 138 kV, and
  - Jackson Road – Concord 138 kV

  2012: $0.8 million

  2013: $0.8 million

- Strawton Wind Farm: PJM IPP project U3-002 has a signed Interconnection Service Agreement (ISA) and is scheduled to be operational by the end of 2012. This wind farm will connect to the Deer Creek – Fisher Body – Mullin 138 kV line. In addition to the wind farm connection, station improvements will be made at Mullin station and at Fisher Body station. Cost information provided reflects only the dollars to be spent by AEP.

  2011: $0.1 million

  2012: $1.0 million

The following provides an update for each of the transmission projects provided in the 2009 IRP. All of the projects have been completed and are now in-service.

- Woods Road Station Project: Woods Road station was established to move 34.5 kV load at Gump Station near Huntertown, Indiana to a new 138 kV station in an attempt to avoid overload conditions on the 34.5 kV system and to improve reliability for the customers.

- Brevini Project: A new customer in Muncie, Indiana had requested service to its facilities that manufactures and tests gearboxes for wind turbines. The projected initial load of 5 MW could be accommodated on the aging 34.5 kV sub-transmission system or existing 12 kV facilities in the area. To reliably serve the load, and to meet the future needs of the area, a radial 5.9 mile, 138 kV line was constructed, with future plans to network the line.

- Twin Branch Area Improvements: The 450 MVA 345/138 kV transformer at Twin Branch Station was projected to overload under several contingencies. A project was initiated in 2007 to replace the existing transformer with a larger 675 MVA 345/138 kV transformer.

- Western Fort Wayne Area Improvements: The Western Fort Wayne area was expected to reach a demand of 190 MVA in 2008. The area transmission facilities were expected to experience thermal overloads and heavy loading under single contingencies. To mitigate the thermal overloads, a new 69 kV line from the Industrial Park Station to the Hadley Station was proposed. The project was initially projected to go in-service in 2008, but due to logistics and material acquisition issues; the project went in-service in 2009.

- Meadow Lake Station: A 200 MW wind farm had requested interconnection to I&M's 345 kV transmission system in Chalmers County, Indiana. The interconnection required construction of a new 345 kV switching station at the developer's expense. The new switching station went in-service in October 2009.

- Wallen Relocation Project: The Indiana Department of Transportation relocated sections of Indiana Route 3 which required relocation of 34.5 kV facilities at I&M's Wallen Station. Significant portions of the relocation projects were reimbursable from the Department of Transportation. The Wallen Relocation Project went in-service in 2009.

- Herbert Monroe Delivery Point: A new switching station was established to serve Paulding Putnam Electric Cooperative Herbert Monroe delivery point at 138 kV.

8) SELECTION OF THE RESOURCE PLAN

8. Selection of the Resource Plan (170 IAC 4-7-8)

A. Modeling Approach

1. The *Strategist*® Model

The *Strategist*® optimization model served as the empirical calculation basis from which the I&M-specific and AEP-East capacity requirements evaluations were examined and recommendations were made. As will be identified, as part of this iterative process, *Strategist*® offers unique portfolios of resource options that can be assessed not only from a discrete, revenue requirement basis, but also for purposes of performing additional risk analysis outside the tool.

As its objective function, *Strategist*® determines the regulatory least-cost resource mix for the generation system being assessed. The solution is bounded by a user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

Strategist® develops a discrete macro (zone-specific) least-cost resource mix for a system by incorporating a variety of expansion planning assumptions including:

- Resource alternative characteristics (e.g. capital cost, construction period, project life.)
- Operating parameters (e.g. capacity ratings, heat rates, outage rates, emission effluent rates, unit minimum downturn levels, must-run status, etc.) of existing and new units
- Unit disposition (retirement / mothballing)
- Delivered fuel prices
- Prices of external market energy and capacity as well as SO_2, NO_X, and CO_2 emission allowances
- Reliability constraints (in this study, minimum reserve margin targets)

- Emission limits and environmental compliance options

These assumptions, and others, are considered in developing an integrated plan that best fits the utility system being analyzed. *Strategist®* does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only supply and demand resource COS changes from plan-to-plan, not fixed, embedded costs associated with existing generating capacity that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital spends for transmission interconnection costs.

Specifically, *Strategist®* includes and recognizes in its incremental, largely generation revenue requirement output profile:

- Fixed costs of capacity additions, i.e. carrying charges on incremental capacity additions (based on an I&M-specific, or weighted average AEP System cost of capital), and fixed O&M.

- Fixed costs of any capacity purchases.

- Program costs of (incremental) DR/EE/IVVC alternatives.

- Variable costs associated with I&M's or the entire fleet of AEP-East's new and existing generating units (developed using the model's probabilistic unit dispatch optimization engine). This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs.

- Market revenues from external energy transactions (i.e., Off-System Sales) are netted against these costs under this ratemaking/revenue requirement format.

In the PROVIEW module of *Strategist®*, the least-cost expansion plan, measured by the Cumulative Present Worth of Revenue Requirements (CPW), is empirically formulated from potentially hundreds of thousands of possible resource alternative combinations created by the module's chronological dynamic programming algorithm. On an annual basis, each capacity resource alternative combination that satisfies various user-defined constraints (to be discussed below) is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations and the number of feasible states increases exponentially with the number of resource alternatives being considered.

B. Major Modeling Assumptions (170 IAC 4-7-8(2))

1. Planning & Study Period

The economic evaluations of this planning process were carried out over a 2012-2040 planning period.

2. Load & Demand Forecast

The internal load and peak demand forecast is based on the approved 2011 AEP System-East Zone load forecast issued in February 2011.

3. Capacity Modeling Constraints

Since the model's algorithm has the potential for creating such a vast number of alternative combinations and feasible states, it can become an extremely large computational and data storage problem, if not constrained in some manner. The *Strategist*® model includes a number of input variables specifically designed to allow the user to further limit or constrain the size of the problem. There were numerous other known physical and economic issues that needed to be considered and, effectively, "constrained" during the modeling of the long-term capacity needs so as to reduce the problem size within the tool.

- Maintain a PJM-required minimum reserve margin of roughly 15.3% per year.

- Under the terms of the NSR Consent Decree, I&M and AEP agreed to annual SO_2 and NO_X emission limits for its fleet of 16 coal-fueled power plants in Indiana, Kentucky, Ohio, Virginia and West Virginia. These emission limits were met by adjusting the dispatch order of these units during the *Strategist*® economic dispatch modeling.

- In addition to meeting NSR consent Decree emission limits, the SO_2 and NO_X allocations/limits defined under the recently finalized CSAPR for I&M's Indiana and Michigan-domiciled generating units were also met during the *Strategist*® modeling.

- The initial period for consideration of new generation additions was assumed to, minimally, not precede the PJM 2014/15 forward planning year due to AEP—on behalf of its eastern operating affiliates, including I&M—having already committed sufficient UCAP resources. Moreover, considering the uncertainty surrounding the ultimate status and implications of both:

    - the ultimate status or make-up of the AEP Interconnection Agreement; and

    - the ultimate status and impact of additional emerging EPA rulemaking, namely EGU MACT;

- The restriction for consideration of new generation additions was further extended to not precede the PJM 2017/18 planning year given the typical minimal ~5-year timeframe to approve, permit, design & engineer, procure materials, construct and commission new fossil generation resources.

There are many variants of available supply-side and demand-side resource options and types. It is a practical limitation that not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for each of the major duty cycle "families" (baseload, intermediate, and peaking).

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes.

Other factors will be considered that will determine the ultimate technology type (e.g., choices for peaking technologies: GE frame machines "E" or "F," GE LMS100 aeroderivative machines, etc.). The full list of screened supply options is included in Exhibit 3 of the Confidential Supplement.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Strategist®* for each designated duty cycle:

- *Peaking* capacity was modeled as blocks of seven, 86 MW GE-7EA Combustion Turbine units (summer rating of 78.5 MW x 7 = 550 MW), available beginning in 2017. Note: No more than one block could be selected by the model per year.
- *Intermediate* capacity was modeled as single natural gas Combined Cycle (2 x 1 GE-7FA with duct firing platform) units, each rated 618 MW (562 MW summer) available beginning in 2017.
- *Baseload* capacity burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions was considered in selecting the solid fuel baseload capacity alternatives. Two solid fuel alternatives were made available to the model:
    - o 624 MW Ultra Supercritical PC unit (summer rating of 612 MW) where the unit is installed with chilled ammonia carbon capture and storage (CCS) technology that would capture 90% of the unit's CO_2 emissions. This option could be added beginning in 2020.
    - o 637 MW Integrated Gasification Combined Cycle (IGCC) "F" Class unit. This alternative could be added by *Strategist®* beginning in 2020 and;

    In addition, beginning in the year 2022:

    - o *Strategist®* could select an 800 MW (~50%) share of a 1,606 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (771 MW summer)

In order to maintain a balance between peaking, intermediate and baseload capacity resources, only seven Combustion Turbine (CT) units could be added in any year. If the addition of seven CTs was not sufficient to meet reliability requirements in a particular year, the model was required to add either intermediate and/or baseload capacity to meet the reliability targets.

4. Commodity Pricing Scenarios

Three commodity pricing scenarios were developed by AEPSC to enable *Strategist*® to construct resource plans under various long-term pricing conditions. The long-term power sector suite of commodity forecasts are derived from a proprietary model known as *Aurora*^{XMP}. *Aurora*^{XMP} is a long-term fundamental production-costing tool developed by EPIS that is driven by sophisticated user-defined input parameters, not necessarily past performance which many modeling techniques tend to utilize. For instance, unit-specific fuel delivery and emission forecasts established by AEP Fuel, Emissions and Logistics (FEL), are fed into *Aurora*^{XMP}. Likewise, capital costs and performance parameters for various new-build generating options, by duty-type, are vetted through AEP Engineering Services and incorporated in the tool. AEP uses *Aurora*^{XMP} to model the eastern synchronous interconnect as well as ERCOT. In this report, the three distinct long-term commodity pricing scenarios that were developed for *Strategist*® are: a "base" view or, "Fleet Transition – Carbon Adjusted," as well as two sensitivity views including, "Fleet Transition," and "Lower Band." The scenarios are described below with the results shown in Exhibits 8-1 to 8-5.

4a. Fleet Transition-Carbon Adjusted

This represents AEP's current consensus view of all drivers to the development of North American regional power prices. It recognizes relatively lower natural gas prices and increasing natural gas price elasticity - despite increasing consumption from domestic power plants. This phenomenon largely being a function of significant natural gas supplies from emerging shale gas extraction efforts. A major criterion of this "base" scenario reflects AEP managements view that substantive national CO_2 legislation and its attendant carbon pricing will not be in place until the year 2022.

4b. Fleet Transition

Largely the same basis as the above view other than the implementation of a CO_2/carbon pricing regime is assumed to be as early as 2017.

4c. Lower Band

This case should best be viewed as low natural gas/energy price "sensitivity" to the Fleet Transition and Fleet Transition-Carbon Adjusted scenarios. In the near term, Lower Band natural gas prices track the Fleet Transition but in the longer term, natural gas prices represent the even more significant infusion of shale gas. From a statistical perspective this long-term pricing scenario represents approximately a negative one (-1) standard deviation from the "Fleet Transition" scenarios and illustrates the effects of Coal-to-gas substitution at such plausibly lower gas prices. Like the Fleet Transition scenarios, CO_2 mitigation/pricing is assumed to start as early as 2017.

C. Modeling Results (170 IAC 4-7-8(2) and 4-7-8(6))

1. Base Results by Pricing Scenario

Given the three fundamental pricing scenarios developed by AEPSC as listed in the previous section, as well as the modeling constraints and certain planning commitments, *Strategist*® modeling was used to develop the initial plans identified in Exhibits 8-6 and 8-7. With regard to these exhibits, because Renewable assets and a base level of incremental DSM are included in all portfolios, *Strategist*® <u>did not</u> represent them as incremental resources within these comparative plan views.

2. Observations: Needs Assessment

Some I&M specific observations drawn from the initial *Strategist®* profiles reflected on Exhibit 8-6 include:

- No new capacity is required until Tanners Creek 4 is retired, and
- The optimal replacement technology for Tanners Creek 4 is a NGCC.

3. Strategic Portfolio Creation & Evaluation

For this IRP, two views of I&M were considered. First, I&M was modeled as a stand-alone entity in PJM. This recognizes the potential that the AEP-Pool could be either materially modified or terminated over the course of the IRP planning cycle and that no AEP-East companies would have any obligation to provide capacity or energy to any other AEP-East company. A second view assumes the AEP Pool remains in place and the AEP Pool companies would be allocated capacity resources based on their position within the AEP Pool. In this view, optimized portfolios are created for the AEP-East System, which could result in a different amount of capacity being assigned to the AEP Pool companies. The I&M capacity plan is the same under either a "AEP Pool" or "No AEP Pool" scenario. That is, if the AEP Pool remains in place, the only new capacity resource assigned to I&M is a NGCC in 2025, which is the same as under the I&M "No AEP Pool" scenario.

4. I&M Strategic Portfolios

Strategic approaches that were considered when constructing the underlying I&M ('stand-alone') system resource portfolios analyzed include:

- "Base" Plan:

- Retrofit Rockport 1 & 2, and Tanners Creek 4 to be compliant with the proposed EGU MACT and CCR rules, as well as NSR Consent Decree obligations. Retire Tanners Creek 1, 2 & 3 by December 31, 2014 so as not to incur retrofit costs required by the EGU MACT rule. Retire Tanners Creek 4 when it reaches 60 years of life, in 2025, and replace it with a natural gas combined cycle (NGCC) plant.

- "Gas" Plan:
  - Same as the Base plan, except retire Tanners Creek 4 by 2015 and replace with a NGCC in 2017. Between 2015 and 2017, rely on the PJM market for any capacity shortfalls.

- "Market" Plan:
  - Same as the "Gas" plan except rely solely on the market to replace Tanners Creek 4 (i.e., do not replace TC4 with a NGCC.)

5. I&M Portfolio Results

Given the range of three fundamental pricing scenarios developed by AEP-Fundamental Analysis, as well as the modeling constraints and certain planning commitments, *Strategist®* modeling was used to develop the CPWs for the Base Plan, Gas Plan and the Market Plan.

Exhibit 8-6 summarizes the plan portfolios. This exhibit shows the new resources required to meet the RTO IRM requirements as well as plan costs over the full (2011-2040) extended planning horizon, and under the various pricing scenarios.

6. I&M Optimal Portfolio Summary

As suggested in Exhibit 8-6, the Base Plan has the lowest CPW of the three plans under all pricing scenarios. I&M is seeking regulatory approvals to formally implement the underpinnings of this plan – that is, the environmental equipment retrofit of a single Rockport Unit as well as the retirement on Tanners Creek 1-3 by December 31, 2014.

7. I&M Additional Risk Analysis

The Base, Gas, and Market Plan views as set forth by the discrete I&M capacity resource modeling performed using *Strategist®* were analyzed further utilizing the *Aurora*^{XMP} application's "risk modeling" feature described later in Section D. These I&M-specific resource portfolio options created in *Strategist®* and the comparison of the respective incremental, life-cycle revenue requirements show economic results based on specific, very reasonable, yet discrete "point estimates" of the underlying variables that could affect these economics. Using a Monte Carlo technique, the *Aurora*^{XMP} tool offers an additional approach by which to "test" these plans over a distributed range of certain key variables. This provided a "probability-weighted" solution that offers additional insight surrounding relative cost/price risk.

8. Optimum AEP-East Resource Portfolios for Four Economic/Pricing Scenarios

For AEP-East, modeling was performed by treating the entire AEP-East System as one entity, as it is seen by PJM using the Market Plan and the Build Plan. In these portfolios, the AEP-East fleet meets its internal load requirement, buying or selling capacity and energy into the PJM market to satisfy short or long positions. Outside of this modeling, once a resource addition plan is established, the assignment of resources is based on AEP Pool requirements. The Market and Build portfolios were analyzed under economic/pricing scenarios described in Section B4, with the results shown in Exhibit 8-7.

9. AEP-East Optimal Portfolio Summary

As suggested in Exhibit 8-7, the Market Plan portfolio was slightly better than the Build Plan; however, the differences are relatively small. As such, the Market Plan that was optimized under Fleet Transition-Carbon Adjusted pricing will be used as the Base Plan for AEP-East. This plan allows for flexibility in dealing with the uncertainty around the AEP Pool transition and EGU MACT issues.

D. Risk Assessment (170 IAC 4-7-8(5) and 170 IAC 4-7-8(10)(A,B and C))

Once the discretely-modeled plans listed in Chapter 8C were constructed, they were subjected to "stress testing" to ensure that none of the plans had outcomes that were deleterious under an array of input variables.

1. The *Aurora*^{XMP} Model

The *Aurora*^{XMP} model was developed by EPIS, Inc. in the mid 1990's and has been licensed for use by AEP since 2002. *Aurora*^{XMP} is primarily a production costing model using a fundamentals-based, multi-area, transmission constrained dispatch logic in order to simulate real market conditions. At AEP it is used primarily as a long-term optimization tool to forecast mid- and long-term power prices and other industry commodities for all generating units in the Eastern Interconnect and ERCOT.

One of the features of the *Aurora*^{XMP} model is its endogenous risk analysis capabilities for Monte Carlo simulations. For the purposes of this study, a commonly accepted sampling method (the Latin-Hypercube) was employed in order to generate a plausible distribution of risk factors with a relatively small number of samples or risk iterations.

This study focused solely on the I&M portfolio of generating units. One hundred risk iteration runs were performed with six risk factors being sampled. The results take the form of a distribution of possible revenue requirement outcomes for each plan. The input variables or risk factors considered by *Aurora*^{XMP} within this IRP analysis were:

- coal prices,
- natural gas prices,
- power prices,

- CO_2 emissions allowance prices,
- full requirements loads / demand,
- construction costs / carrying costs

These variables were correlated based on historical data.

Monthly Correlation Targets	Natural Gas	Coal Prices	CO_2 Allowance Prices	Power Prices	Demand
Natural Gas	1	0.09	-0.22	0.87	seasonal
Coal Prices		1	0.69	0.19	0.74
CO_2 Allowance Prices			1	-0.14	0.05
Power Prices				1	0.75
Demand					1

Mean (forecast)	0.003	0.002	0.002	0.005	
St Dev (data	0.123	0.018	0.016	0.204	0.11
St Dev (forecast)		0.2	0.019	0.149	

European Futures

European Futures / US Data validated

US
Data

Hypothesized

2. Modeling Process & Results & Sensitivity Analysis (170 IAC 4-7-8(10)(B))

For each portfolio, the difference between its mean and its 95th percentile was identified as Revenue Requirement at Risk (RRaR). The 95th percentile represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of 5.0 percent. The RRaR represents a measure of risk or uncertainty inherent in each portfolio. The larger the RRaR, the greater the level of risk that customers would be subjected to higher rates.

Figure 8-1 illustrates for the Market Plan, the average levels of some key risk factors, both overall and in the simulated outcomes whose Cumulative Present Value (CPV) revenue requirement is roughly equal to or exceeds the upper bound of Revenue Requirement at Risk. While this figure is specific to the Market Plan, the numbers would be very similar under the other plans. (The particular alternative futures producing the highest levels are not necessarily the same between different plans.) The Construction Costs are shown for a different year than the other risk factors because the Market Plan did not utilize new natural gas production until 2025.

Figure 8-1: Key Risk Factors –Means

	Simulated outcomes - Market Plan				
Risk Factor	All Outcomes	RRaR-Exceeding Outcomes			Year
	Mean	Mean	Difference	%Diff	
Coal prices	2.62	3.01	0.39	14.9%	2020
Natural Gas Prices	7.94	9.40	1.46	18.4%	2025
Power Prices	66.24	69.40	3.16	4.8%	2020
CO2 Emissions Allowance Prices	22.64	28.75	6.12	27.0%	2022
Demand	26,492	32,387	5895	22.3%	2020
FOM, Construction Costs / MW	3.50	3.83	0.33	9.3%	2025

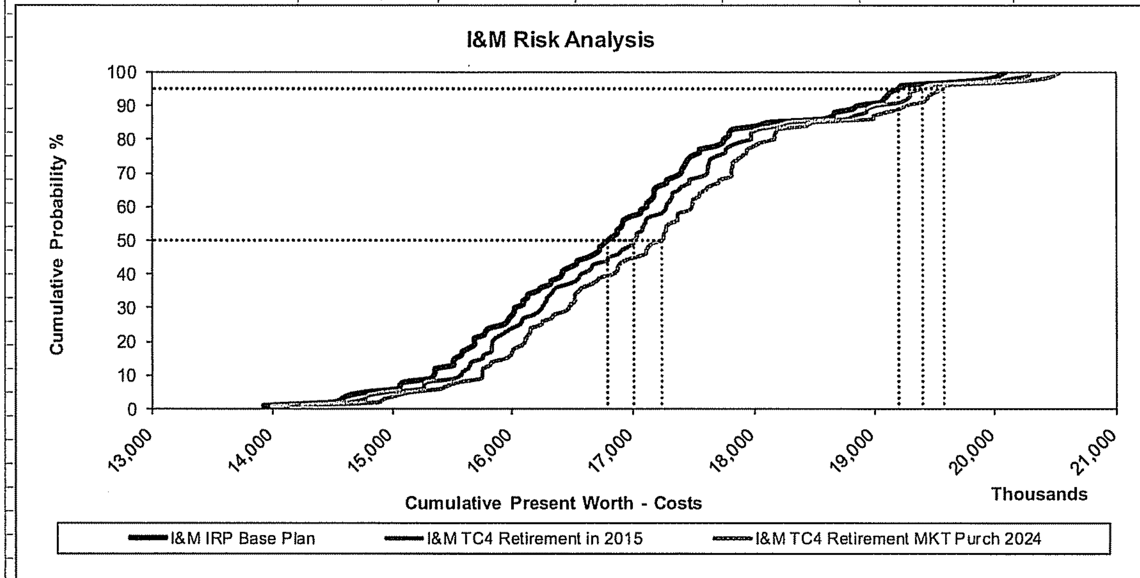
Source: AEP Fundamental Analysis

The price of CO_2 allowances and Demand are greater among the RRaR-exceeding outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between that "tail" and mean outcomes are 27.0% to 22.3% which is somewhat greater than the relative difference of other risk factors.

It might be assumed that the very worst possible futures would be characterized by high fuel and allowance prices and low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with high fuel prices would essentially always have high power prices. Likewise the risk factor analysis implies an inverse correlation between CO_2 allowance prices and some of the other risk factors that determine the tail cases, so that in these tail cases, the average CO_2 allowance price is actually less than the average across all possible futures.

Figure 8-2 shows the distribution of outcomes for each of the three plans that were evaluated – the Base Plan, Gas Plan, and Market Plan. Note that these CPV's are consistent with the CPW values calculated using the *Strategist®* tool, with the Base Plan being the lowest cost plan and the Gas and Market plans slightly more expensive. The importance of this evaluation, though, is not in matching the *Strategist®* results, but in examining the relative risk among the portfolios. As the table below Figure 8-2 shows, the difference between the 50th and 95th probability percentile is fairly consistent for each portfolio. This leads to the conclusion that the effects of market risk are similar to the risks associated with construction costs and fuel prices. This reinforces the conclusions from the *Strategist®* optimization analysis – that there is no particular advantage or disadvantage between the Base, Gas and Market portfolios. The table also shows, the difference between the 50th and 95th probability percentile is fairly consistent for each portfolio. This leads us to the conclusion that the effects of market risk are similar to the risks associated with construction costs and fuel prices. This reinforces the conclusions from the *Strategist®* optimization analysis – that there is no particular advantage or disadvantage between the Base, Gas and Market portfolios.

Figure 8-2 – I&M Risk Analysis - Cumulative Present Worth



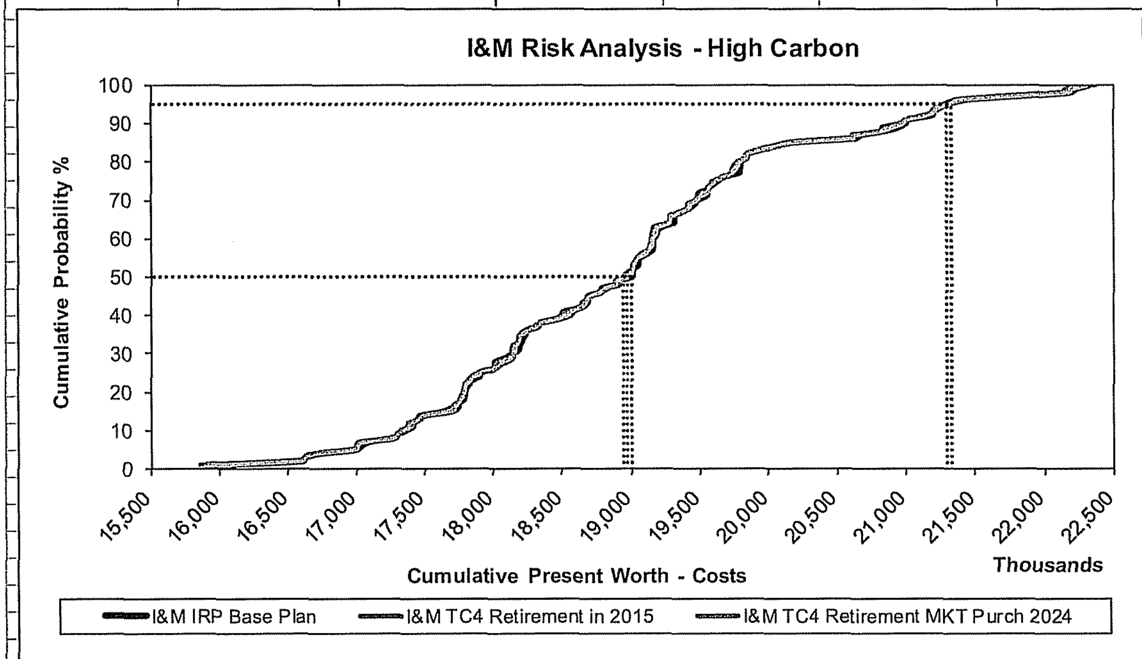
Percentile	I&M IRP Base Plan	I&M TC4 Retirement in 2015	I&M TC4 Retirement MKT Purch 2024	Delta Base - Optimized	Delta Base - Base Plus CES	Delta Optimized - Base Plus CES
50	16,789,247	17,007,095	17,238,026	(217,848)	(448,780)	(230,932)
95	19,205,376	19,404,181	19,579,534	(198,804)	(374,158)	(175,354)
	2,416,130	2,397,086	2,341,508	19,044	74,622	55,578

Source: AEP Fundamental Analysis

An additional sensitivity, related to the cost of GHG/carbon emissions, was also performed. In this sensitivity analysis carbon costs were, in fact, doubled from the base prices assumed in the first set of evaluations performed(*i.e.*, increasing a nominal CO_2 pricing range of \$15-\$30/tonne to as much as \$30-\$60/tonne over the long-term study period). Although the Company believes that such extreme CO_2/carbon pricing range is not plausible due to its attendant impact on regional energy prices, this sensitivity exercise is nonetheless valid to more rigorously "stress" these risk assessments applicable to these alternative planning scenarios. In that regard, however, it is also important to realize that all other variables were assumed to have a similar distribution as the first set of evaluations (*i.e.*, the change in CO_2/carbon pricing was <u>not</u> assumed to have an effect on other variables, such as energy pricing). This was done to somewhat "isolate" the impact of carbon costs on portfolio risk. As can be seen in Figure 8-3, the CPW for all portfolios increases, as expected, however the resulting distribution reduces the difference among the portfolios. The Base portfolio is slightly more expensive than the Gas or Market portfolios at the 50th percentile level, however it is the least expensive portfolio at the 95th percentile level.

The conclusion that can be drawn from this analysis is that under a more restrictive (*i.e.*, higher cost) carbon regime, the three portfolios would become essentially equivalent from a cost/risk perspective. More importantly, it would indicate that the "Base" long-term I&M resource plan being set forth would not be compromised. That is, even under an *extreme* CO_2/carbon view, this Base Plan would continue to be an acceptable alternative from a cost perspective.

Figure 8-3 – I&M Risk Analysis - Cumulative Present Worth



Percentile	I&M IRP Base Plan	I&M TC4 Retirement in 2015	I&M TC4 Retirement MKT Purch 2024	Delta Base - Gas	Delta Base - Mkt	Delta Gas - Mkt
50	19,002,607	18,943,227	18,970,291	59,380	32,316	(27,063)
95	21,296,814	21,328,408	21,334,536	(31,594)	(37,722)	(6,127)
	2,294,207	2,385,181	2,364,245	(90,974)	(70,038)	20,936

E. I&M Current Plan (170 IAC 4-7-8(1))

The optimization results and associated risk modeling of this IRP show that, for I&M as a potential stand-alone entity in the PJM RTO, the Base Plan results in lower costs than the Gas Plan or the Market Plan. Given the uncertainty surrounding the final outcome of both the EGU MACT rulemaking and the AEP Pool termination, the Company is proposing the plan which has the maximum flexibility – the Base Plan. The Base Plan also subjects I&M customers to an acceptable level of risk relative to the Gas and Market plans. The supply-side expansion plan represented in this report is also influenced by I&M's commitment to DSM programs, renewables, and to the need for compliance with environmental regulations. Following are some highlights of the "embedded" features of the plan.

- Potential DSM programs are estimated to reduce the I&M peak demand by 423 MW (summer) and 269 MW (winter) and energy requirements by 1,720 GWh by the end of the forecast period (2031). This is recognized prior to establishing the plan for supply-side resources.
- I&M is already receiving energy from two wind projects with a total nameplate rating of 150 MW. The current plan for I&M reflects no additional wind capacity until 2013.
- In the long-term, 562 MW (summer) of intermediate (NGCC) capacity is projected to be added by 2025.

Assuming I&M is a stand-alone company in PJM beginning in the 2016/17 planning year, I&M may purchase capacity from or sell capacity to the market, or enter into bilateral agreements with either the current AEP-East companies or other generation entities as needed.

Exhibit 8-8 provides the I&M expansion plan assuming I&M is a stand-alone member in PJM after 2014. I&M will satisfy its reserve margin requirements through 2024 using a combination of existing capacity and demand response measures as shown in Exhibit 8-10.

Exhibit 8-8 also shows the proposed I&M resource plan assuming I&M remains part of the AEP Pool under its current construct. *Note that there is no change in the I&M resource plan between the AEP Pool and No AEP Pool cases.*

F. AEP-East Current Plan (170 IAC 4-7-8(1))

The AEP-East plan is shown in Exhibit 8-9. This plan is based on the Market portfolio analyzed in *Strategist*®. AEP-East will satisfy its reserve margin requirements using a combination of capacity purchases and demand response measures as shown in Exhibit 8-11. Additional renewable resources are included in the AEP-East plan to comply with individual state mandates. Unit retirements and environmental retrofits assume an EGU MACT implementation date of January 1, 2015.

G. IRP Summary

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in significant modifications in the resource plan reflected for both I&M and AEP-East. I&M and AEP are confident that the resource plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, construction cost estimates, and final AEP Pool status. As such changes and assumptions are recognized, updated, and refined, input information will be reevaluated and resource plans modified as appropriate.

H. Financial Effects (170 IAC 4-7-8 (3)) and 170 IAC 4-7-8(8)(A, B, D and E))

The average "real" rate per kWh expected to be paid by I&M customers from

2011 to 2021 is shown in Exhibit 8-12.

The Company, after receiving adequate rate relief, expects to be able to finance its utility plant additions with both internal and external funds at reasonable costs. As previously stated, I&M does not expect to add any major new baseload generation during the 2012-2021 period, however, environmental retrofit projects at Rockport and Tanners Creek in addition to life-cycle projects at the Cook Nuclear Plant will require significant investments.

Also, Exhibit 8-12 provides the present value total revenue requirement (G, T, and D) including the utility's resource plan, stated in total dollars, in dollars per kilowatt-hour delivered, with a discount rate specified as required in 170 IAC 4-7-8 (3) for the 2011-2022 period. Information beyond that period is not available.

9) AVOIDED COSTS

9. Avoided Costs (170 IAC 4-7-4(16))

A. Avoided Generation Capacity Cost (170 IAC 4-7-4(16)(A); 4-7-6(b)(3); 4-7-8(C))

In the short term, the best representation of avoided capacity cost is the cost of purchasing capacity in the market. Market prices are expected to rise in time to approximately the cost of a new combustion turbine unit. The capacity costs in Exhibit 9-1, which are representative of the described costs, have been adjusted upward to represent a per-kW-of-load figure, including the impact of a change in load on losses and reserve requirements.

B. Avoided Transmission Capacity Cost (170 IAC 4-7-4(16)(B)) and (170 IAC 4-7-6(a)(6)(D))

The transmission system is planned, constructed, and operated to serve not only the load physically connected to the Company's wires but also to operate adequately and reliably with interconnected systems.

The transmission system must have the capacity to reliably link generation resources with the various load centers and must be operated to provide this function even during forced and scheduled outages of critical transmission facilities. Conditions on neighboring systems and resulting parallel flows are other factors that also influence the capacity of the transmission system. Expansions of the transmission system are location specific and dependent upon the particular circumstances of load and connected generation at each location. Accordingly, unlike generation, the concept of transmission-related avoided cost is ever changing, based on the location being considered.

Because transmission expansion is so dependent upon location and factors beyond the Company's control, such as generation of others and conditions on interconnected systems, it is nearly impossible to determine a transmission-related avoided cost that has real meaning or is reliable for the Company other than on a case-by-case basis.

C. Avoided Distribution Capacity Cost (170 IAC 4-7-4(16)(C))

The distribution system is planned, constructed, and operated to serve not only the load physically connected to I&M's wires, but also to operate adequately and reliably with generation and transmission connected to the distribution system.

The distribution system must have the capacity to reliably carry generation resources to various load centers and customers. Expansions of the distribution system are location-specific and dependent upon the particular circumstances of load, interconnected transmission, and connected generation at each location. Accordingly, unlike generation, the concept of distribution-related avoided cost is ever changing, based on the location being considered.

Because distribution expansion is so dependent upon location and factors beyond the Company's control, such as generation of others, local customer load changes and demand management, and local customer load diversity, it is nearly impossible to determine a distribution-related avoided cost that has real meaning or is reliable for the Company other than on a case-by-case basis.

D. Avoided Operating Cost (170 IAC 4-7-4(16)(D) and 170 IAC 4-7-6-(a)(6)(D))

I&M's avoided operating cost including fuel, plant O&M, spinning reserve, and emission allowances, excluding transmission and distribution losses as discussed above, is provided in Exhibit 9-2, to the extent it is available. These data were developed using the PROMOD IV® production cost model.

10) SHORT-TERM ACTION PLAN

10. Short-Term Action Plan (170 IAC 4-7-9)

The I&M Short-Term Action Plan applies to the two-year period November 2011-2013. The I&M resource plan is regularly reviewed and modified as assumptions, scenarios, and sensitivities are examined and tested based upon new information that becomes available.

A. Current Supply-Side Commitments

Utilizing its adequate supply of diversely-fueled resources, supported by its participation in the AEP Pool agreement, I&M expects to continue to provide its retail and wholesale customers with reliable electric service at a reasonable price by pursuing the following course of action:

- Continue to acquire wind resources, as needed to meet or correspond to Indiana renewable goals and Michigan renewable standards.
- Upon approval of a CPCN, begin engineering and construction activities required to add pollution control equipment to Rockport Plant
- Continue to pursue DSM alternatives
- Continue investigating and evaluating pollution control technologies for Tanners Creek 4.
- Continue with Cook LCM related activities

B. Demand-Side Assessment

I&M's short-term action plan includes continuing the monitoring and evaluation of DSM programs and continuing the enhancement of the DSM planning process. I&M plans to continue to assess cost-effective DSM opportunities that could potentially be offered. As further discussed in Chapter 4, I&M has in place a diverse selection of time-of-use rate options and other conservation-related tariffs / programs, including interruptible tariffs, designed to allow customers to achieve savings for taking actions which result in the more efficient use of electricity. See Demand Side Management programs, Chapter 4E, for a listing of I&M's tariffs that contain time-of-use, interruptible and demand response provisions. Included in this listing are the demand response riders approved by the IURC in 2011 in Cause No. 43566 PJM 1. These PJM-related riders are Emergency Demand Response (D.R.S. 1), Economic Demand Response (D.R.S. 2) and Ancillary Service Demand Response (D.R.S. 3). I&M will continue to offer tariffs that encourage its customers to make energy-efficient and cost saving decisions by participating in time-of-use, demand response, and interruptible load programs.

Particular to I&M, in accordance with the Order of the Commission in Cause No. 43959 dated April 27, 2011, I&M continues working as a member of the Program Implementation Oversight Board (OSB) to implement the programs contained in I&M's Three Year DSM Plan which aligns with requirements set forth in Cause 42693, the Phase II Generic Order. The members of the OSB include I&M, OUCC, Indiana Michigan Power Company Industrial Group, Citizens Action Coalition of Indiana, Inc. ("CAC"), and the City of Fort Wayne. I&M's Three Year DSM Plan contains the programs listed in the table below.

		Energy Savings (MWh)			
I&M THREE YEAR DSM PLAN SAVINGS PROJECTIONS		**2011 Projected**	**2012 Projected**	**2013 Projected**	**Program 3 Year Total**
Residential Lighting		15,377	21,784	0	46,131
Residential Home Energy Audit		2,166	4,164	6,161	12,668
Residential Low Income Weatherization		1,724	1,724	1,724	5,810
Energy Efficient Schools		1,730	2,141	2,141	6,067
C&I Prescriptive		23,098	44,754	59,191	129,934
Total Core Programs		**44,095**	**74,567**	**69,217**	**200,610**
Residential Appliance Recycling		4,106	9,580	6,843	21,213
Residential On-Line Audit		3,792	7,293	10,793	21,878
Residential New Construction		296	591	739	1,626
Residential Solar Siting		53	105	158	316
Residential Home Weatherization		751	1,501	2,249	4,501
Residential Home Energy Reporting		18,400	9,200	9,200	36,800
Residential Peak Reduction		72	144	216	432
Renewables & Demonstration		24	24	24	72
C&I Incentives		4,826	12,364	29,674	46,984
C&I Retro-Commissioning Lite		12,921	25,842	34,456	73,219
C&I HVAC Optimization		2,819	8,458	16,916	28,193
C&I Audit		844	1,606	2,636	5,086
C&I New Construction		1,030	1,760	2,434	5,224
Total Core Plus Programs		**49,934**	**78,468**	**116,338**	**245,544**
TOTAL ENERGY SAVINGS PROJECTION		**94,029**	**153,035**	**185,555**	
I&M PHASE II ORDER YEARLY ENERGY SAVINGS GOAL		**77,400**	**108,400**	**142,300**	

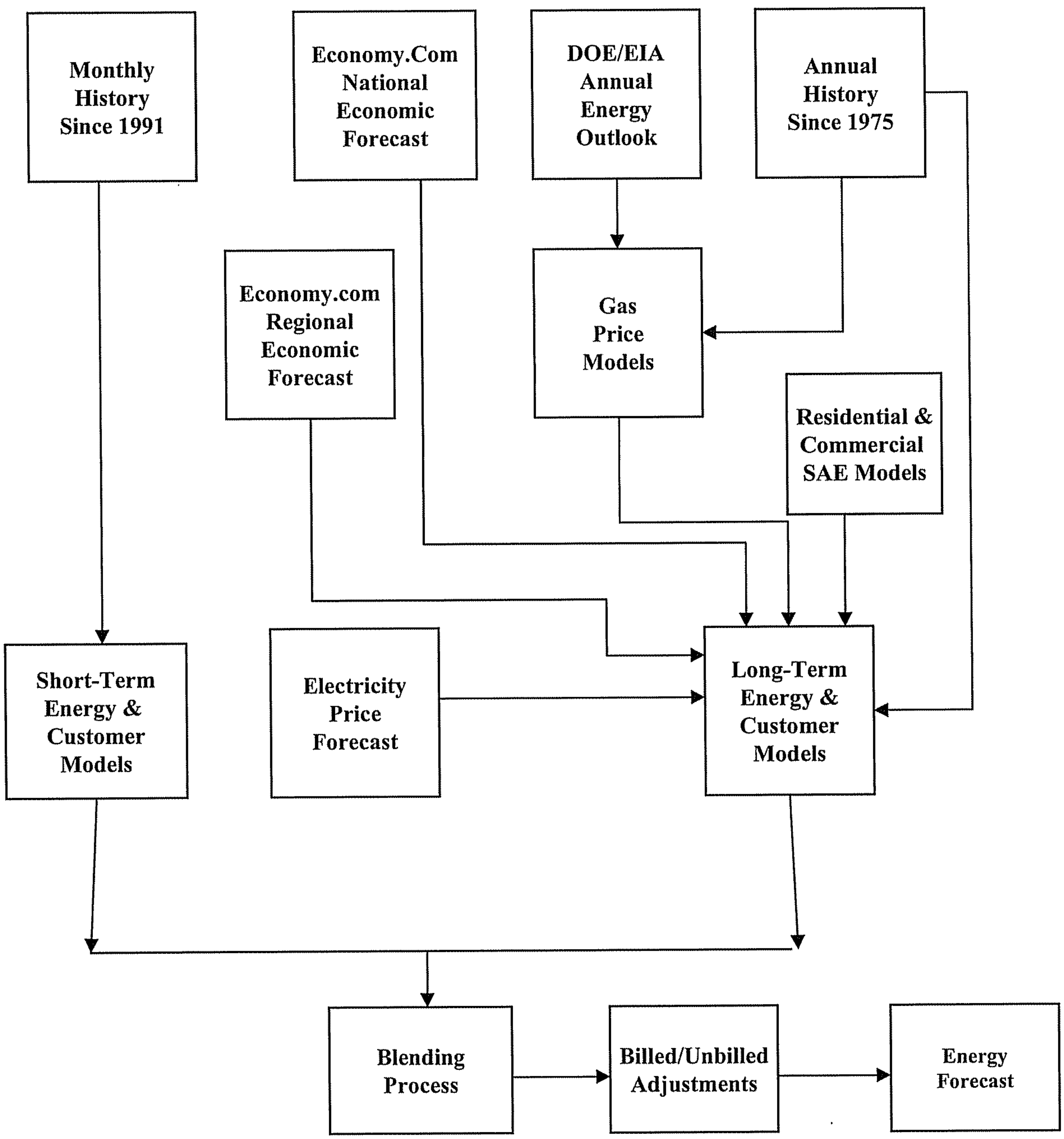
I&M is an active participant in the DSM Coordination Committee (DSMCC) established as directed in Cause 42693. The DSMCC is currently working with the Third Party Administrator (TPA) to establish statewide Core Programs and to transition existing utility administered Core Programs to the statewide model.

The Modified Action Plan (Cause 43959) and Action Plan (Cause 43769), along with other Exhibits presented in Cause 43959, contain detailed descriptions of the programs including all cost-effectiveness tests. The breadth of DSM programs contained within the portfolio of programs approved in Cause 43959 (3 Year DSM Plan) addresses "lost opportunities" with the availability of "new construction" programs, as well as comprehensively addressing many sectors and facets of residential and commercial energy consumption.

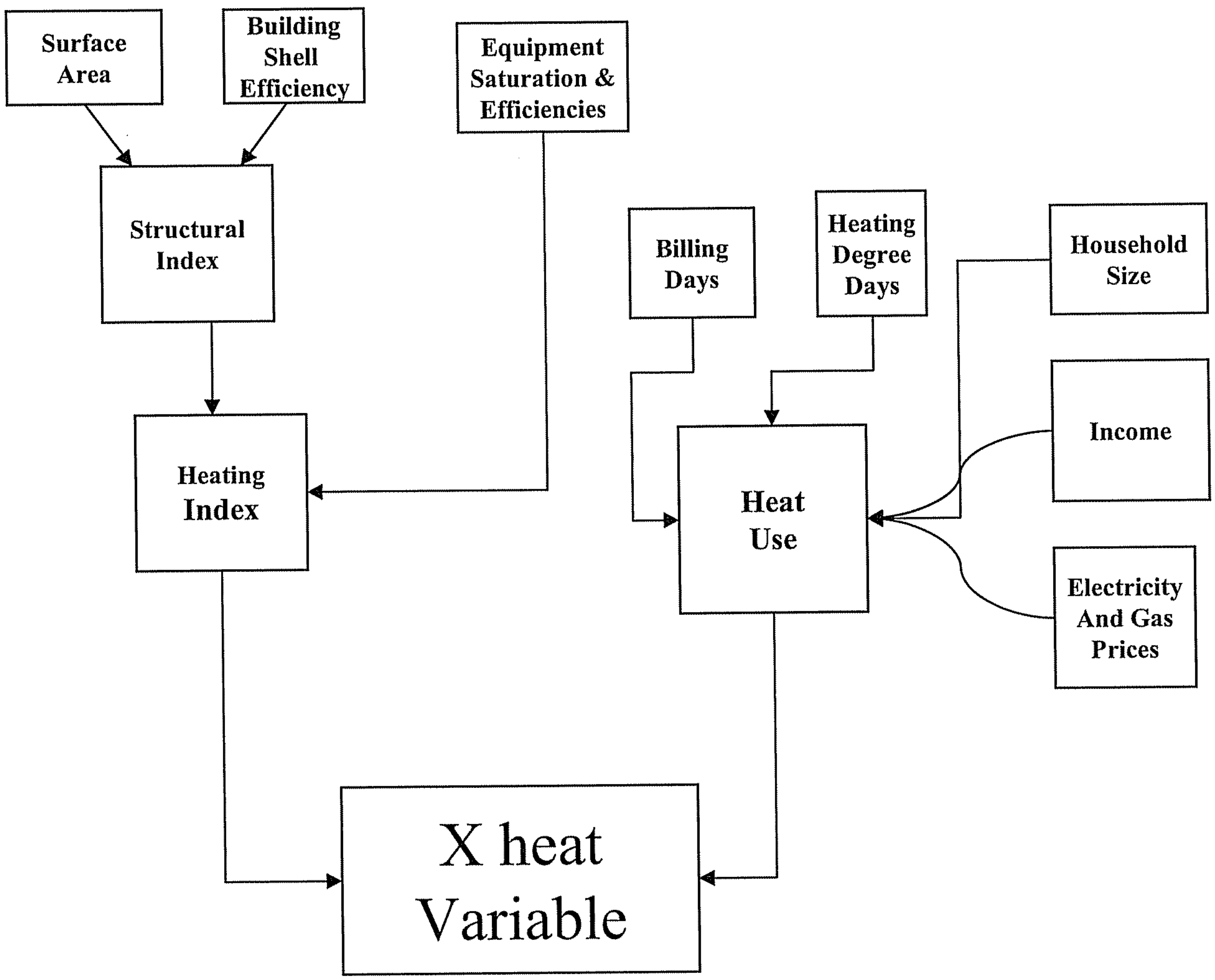
I&M recognizes that there are a variety of methods available to effect demand and energy reductions, including utility-sponsored programs. The judicious deployment of cost-effective demand response tools such as time-of-day, seasonal, and interruptible tariffs to influence the peak use of electricity is a powerful method to incorporate into the IRP and can help delay the need for new supply side investment.

11) EXHIBITS

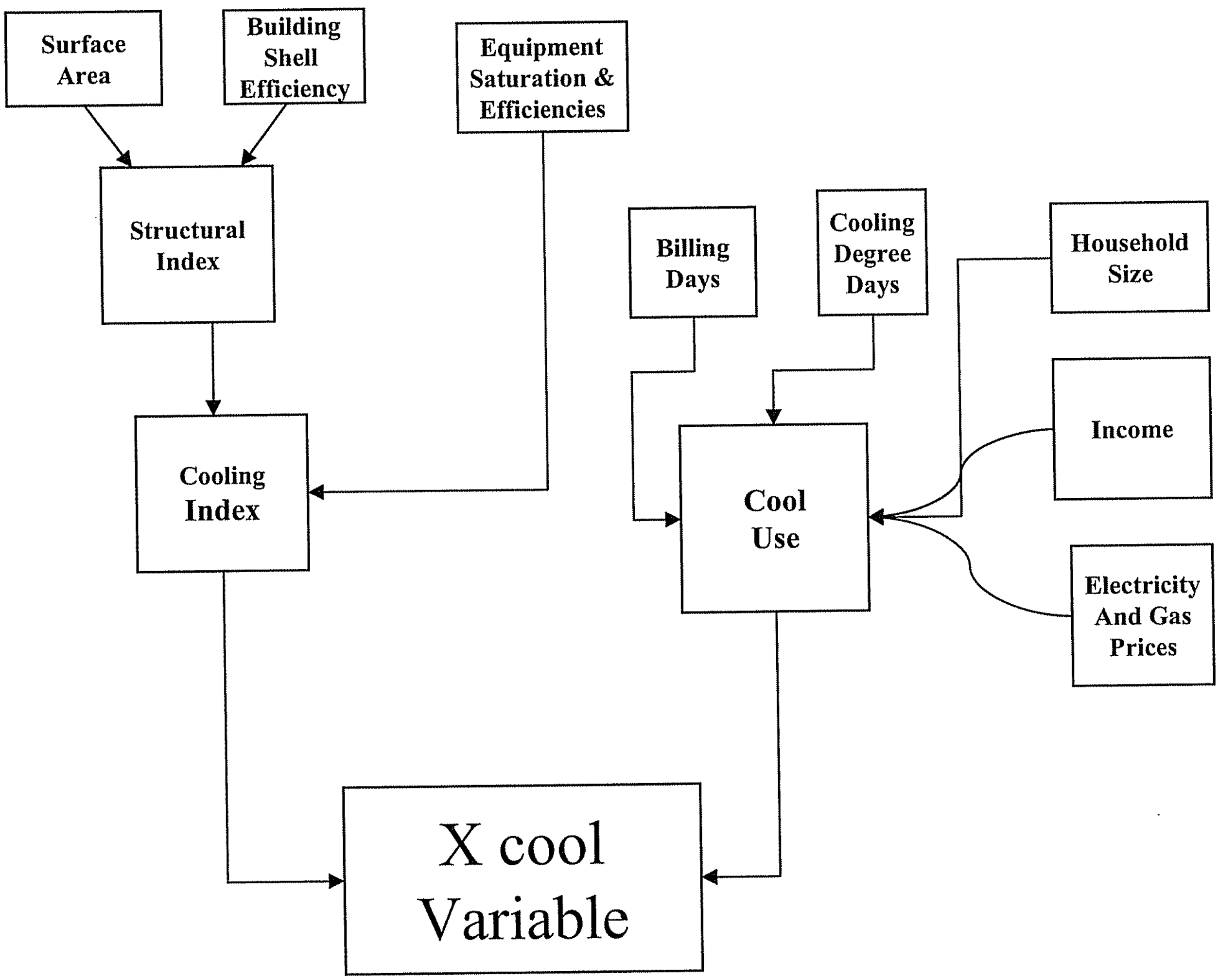
Indiana Michigan Power Company
Internal Energy Requirements Forecasting Method



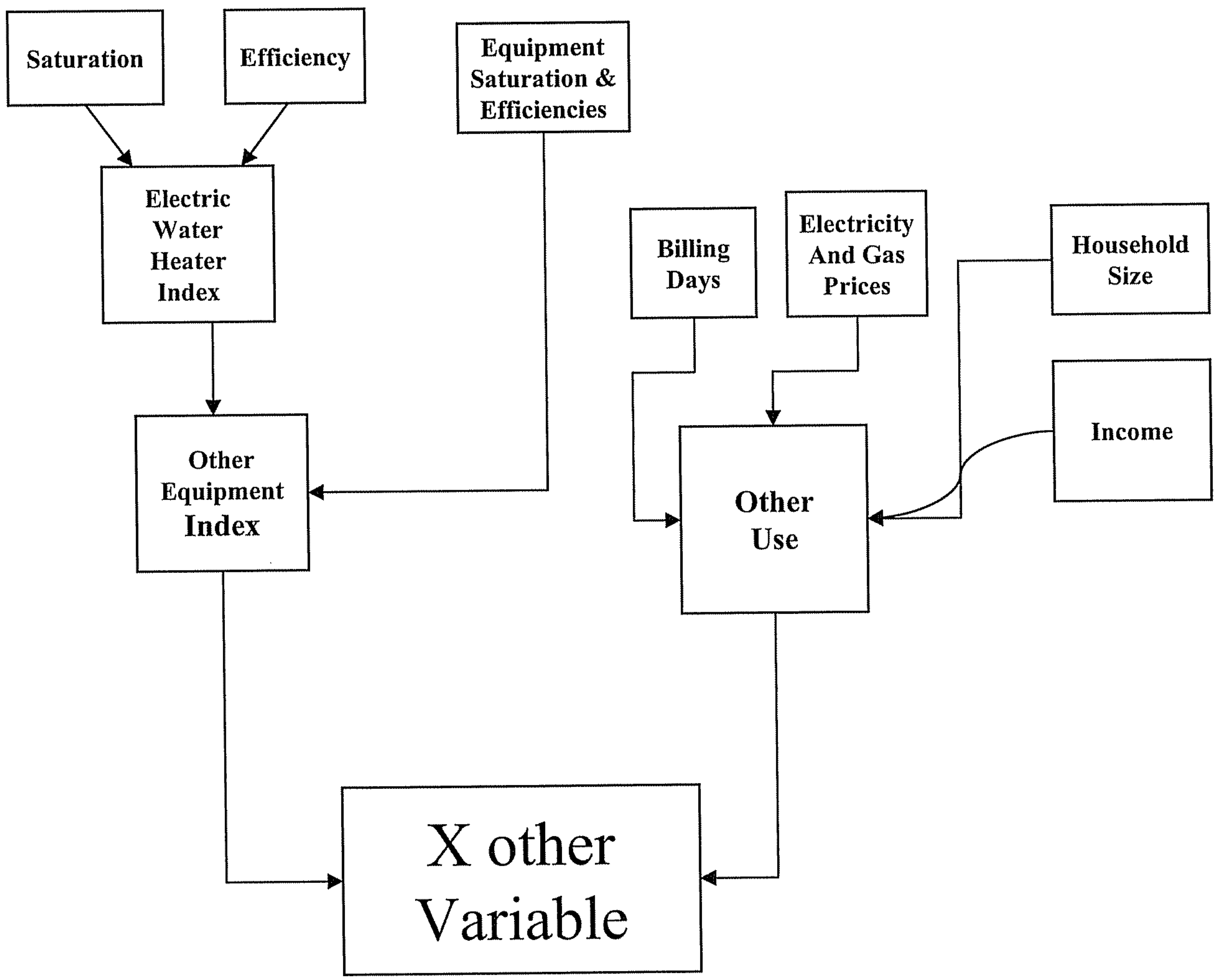
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X heat Variable



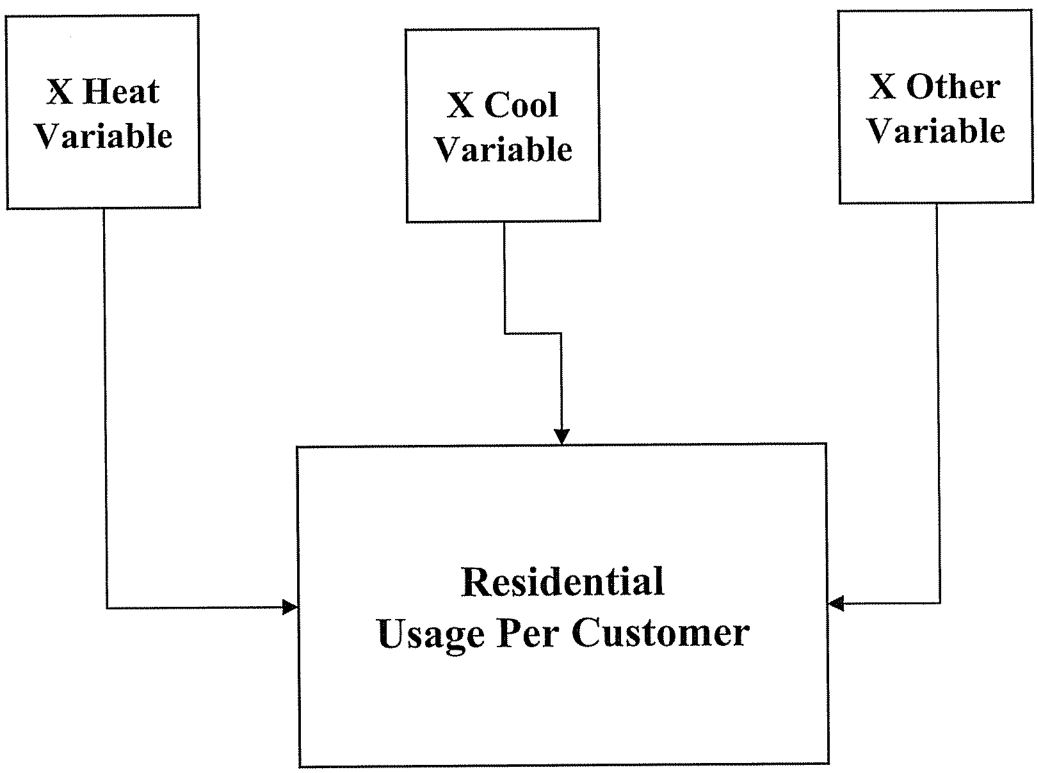
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X cool Variable



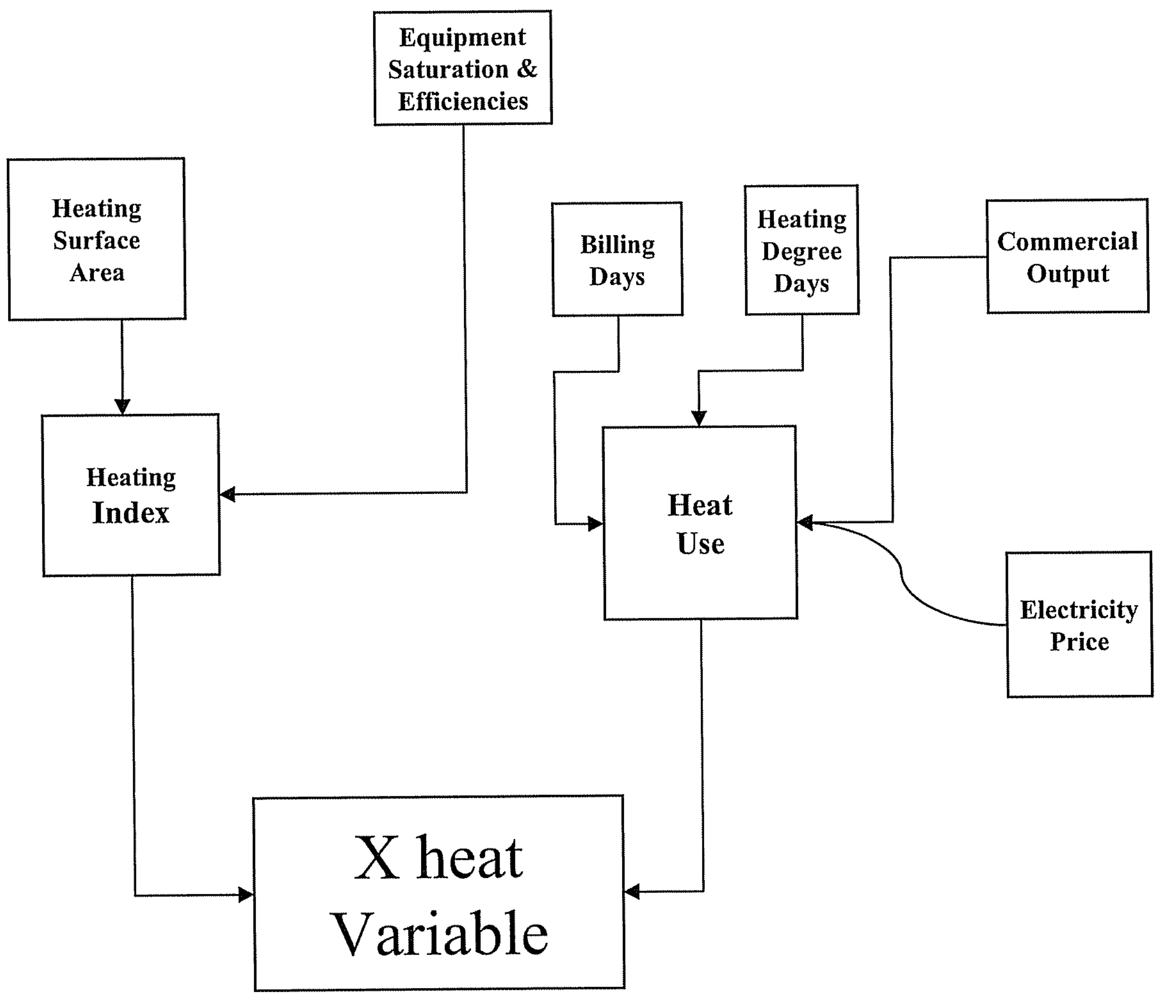
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X other Variable



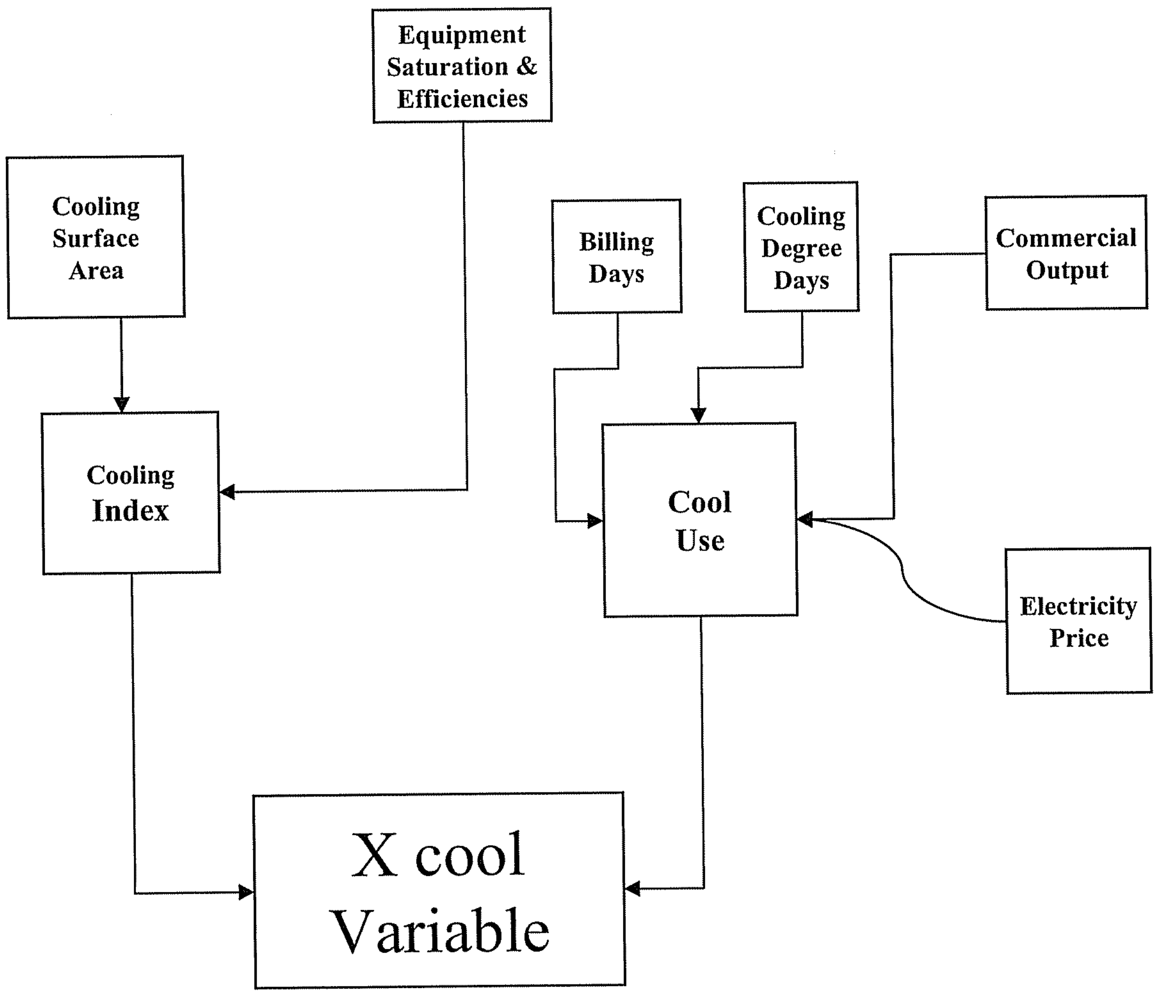
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)



Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X heat Variable



Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X cool Variable



Indiana Michigan Power Company
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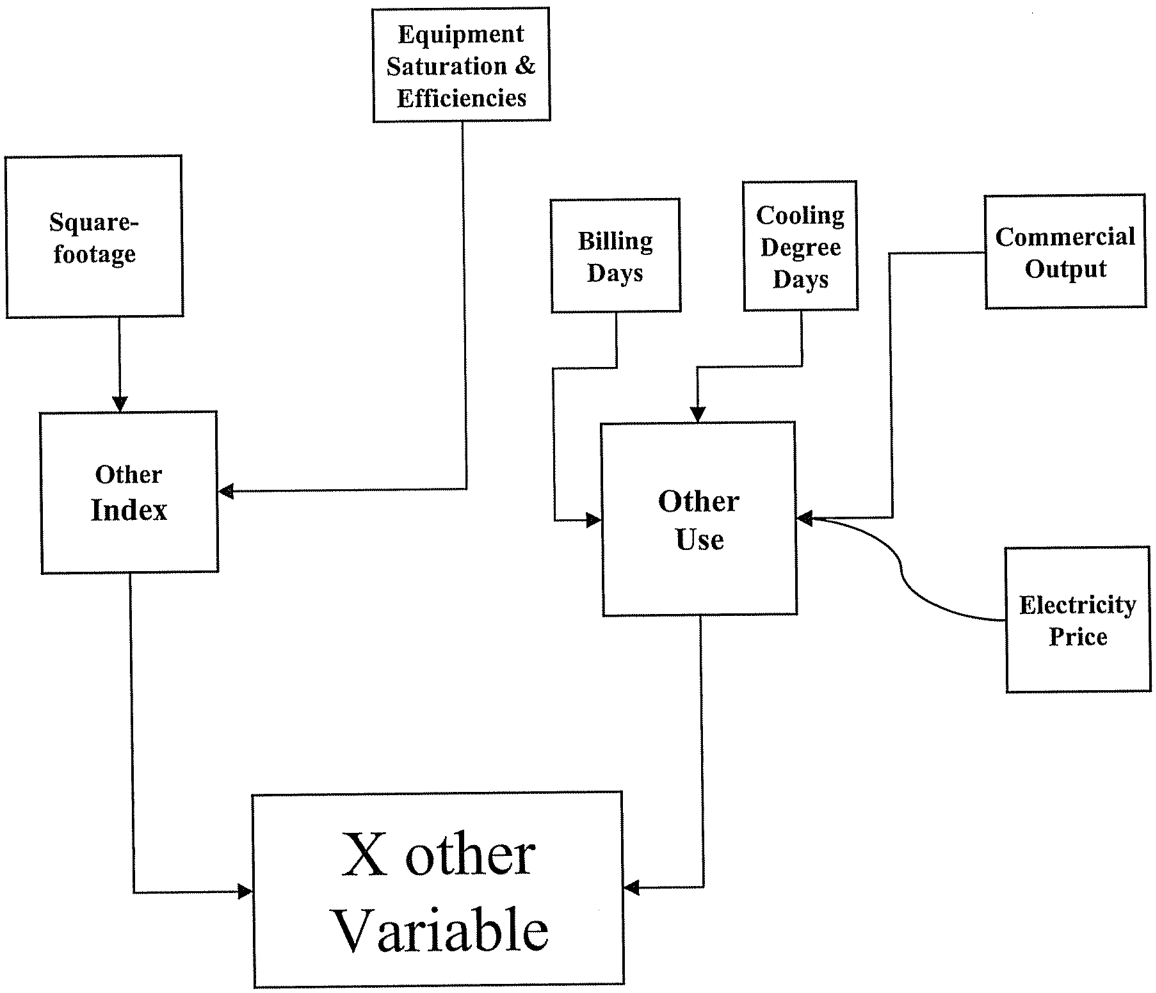
X other Variable



Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)

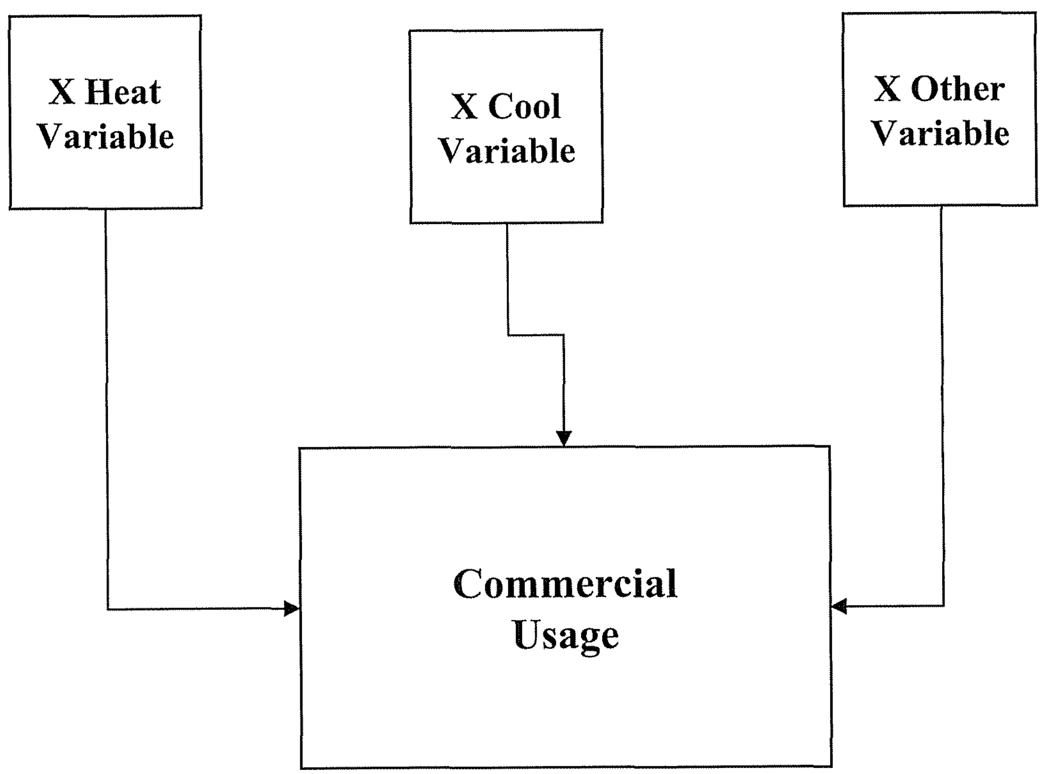


Exhibit 3-2

Indiana Michigan Power Company Peak Demand and Internal Energy Requirements Forecast Process – Sequential Steps

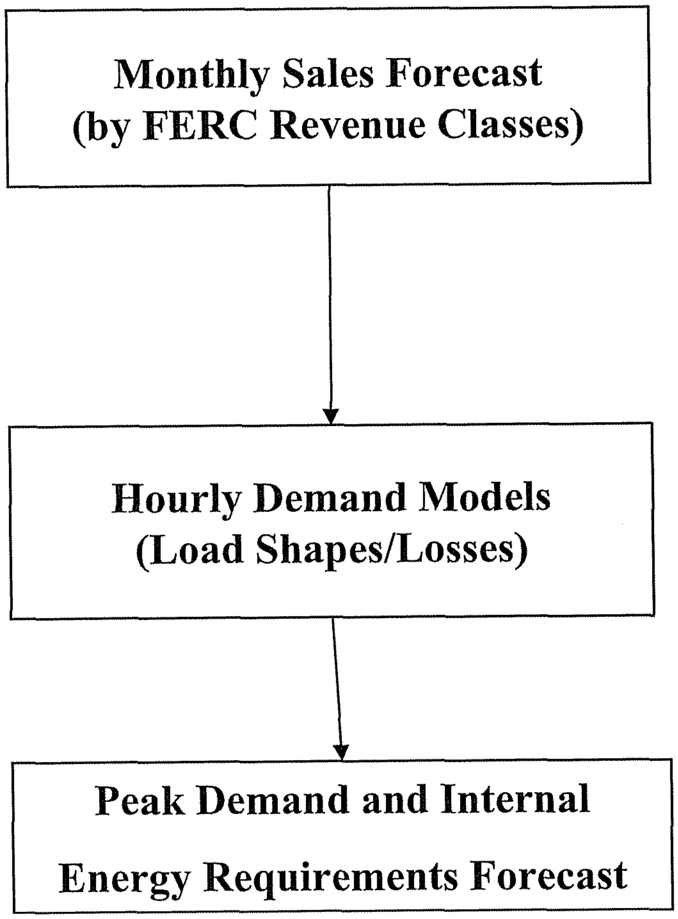


Exhibit 3-3

Indiana Michigan Power Company
Annual Internal Energy Requirements and Growth Rates
2001-2031

Year	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2001	5,413	---	4,773	---	7,914	---	2,321	---	1,863	---	22,284	---
2002	5,778	6.7	4,896	2.6	8,198	3.6	2,454	5.7	1,967	5.6	23,293	4.5
2003	5,476	-5.2	4,777	-2.4	7,878	-3.9	2,542	3.6	2,202	11.9	22,876	-1.8
2004	5,524	0.9	4,894	2.4	8,109	2.9	2,757	8.4	1,678	-23.8	22,962	0.4
2005	5,986	8.4	5,090	4.0	8,090	-0.2	2,253	-18.3	1,990	18.6	23,407	1.9
2006	5,784	-3.4	5,068	-0.4	8,049	-0.5	3,580	58.9	1,939	-2.6	24,419	4.3
2007	6,132	6.0	5,373	6.0	7,967	-1.0	4,620	29.1	1,921	-0.9	26,013	6.5
2008	6,059	-1.2	5,272	-1.9	7,536	-5.4	4,629	0.2	1,953	1.7	25,448	-2.2
2009	5,767	-4.8	5,038	-4.4	6,762	-10.3	4,628	0.0	2,101	7.5	24,296	-4.5
2010	6,083	5.5	5,121	1.6	7,445	10.1	4,887	5.6	2,293	9.1	25,828	6.3
2011*	5,925	-2.6	5,133	0.2	7,513	0.9	4,954	1.4	1,986	-13.4	25,512	-1.2
Forecast												
2012	5,890	-0.6	5,243	2.1	7,826	4.2	5,065	2.2	2,145	8.0	26,169	2.6
2013	5,894	0.1	5,304	1.2	8,098	3.5	5,210	2.9	2,115	-1.4	26,621	1.7
2014	5,850	-0.7	5,267	-0.7	7,967	-1.6	5,276	1.3	2,140	1.2	26,500	-0.5
2015	5,796	-0.9	5,237	-0.6	7,824	-1.8	5,359	1.6	2,150	0.5	26,366	-0.5
2016	5,749	-0.8	5,208	-0.5	7,732	-1.2	5,411	1.0	2,143	-0.3	26,244	-0.5
2017	5,707	-0.7	5,187	-0.4	7,657	-1.0	5,491	1.5	2,116	-1.3	26,158	-0.3
2018	5,659	-0.8	5,161	-0.5	7,575	-1.1	5,542	0.9	2,103	-0.6	26,039	-0.5
2019	5,614	-0.8	5,142	-0.4	7,476	-1.3	5,620	1.4	2,104	0.1	25,956	-0.3
2020	5,598	-0.3	5,141	0.0	7,407	-0.9	5,665	0.8	2,096	-0.4	25,907	-0.2
2021	5,613	0.3	5,167	0.5	7,383	-0.3	5,739	1.3	2,077	-0.9	25,978	0.3
2022	5,617	0.1	5,178	0.2	7,360	-0.3	5,787	0.8	2,102	1.2	26,044	0.3
2023	5,633	0.3	5,202	0.5	7,389	0.4	5,814	0.5	2,115	0.6	26,152	0.4
2024	5,660	0.5	5,239	0.7	7,443	0.7	5,842	0.5	2,125	0.4	26,308	0.6
2025	5,695	0.6	5,293	1.0	7,510	0.9	5,872	0.5	2,113	-0.5	26,484	0.7
2026	5,718	0.4	5,334	0.8	7,566	0.7	5,899	0.5	2,142	1.4	26,659	0.7
2027	5,749	0.5	5,381	0.9	7,627	0.8	5,928	0.5	2,150	0.4	26,834	0.7
2028	5,768	0.3	5,415	0.6	7,683	0.7	5,958	0.5	2,199	2.3	27,023	0.7
2029	5,815	0.8	5,481	1.2	7,765	1.1	5,991	0.6	2,163	-1.6	27,215	0.7
2030	5,836	0.4	5,521	0.7	7,831	0.9	6,026	0.6	2,202	1.8	27,416	0.7
2031	5,874	0.6	5,568	0.8	7,904	0.9	6,058	0.5	2,219	0.7	27,622	0.8

***Includes 6 months actual and 6 months forecast data.**

Average Annual Growth Rates	Residential	Commercial	Industrial	Other Internal	Losses	Total
2001-2011	0.9	0.7	-0.5	7.9	0.6	1.4
2012-2031	0.0	0.3	0.1	0.9	0.2	0.3

Exhibit 3-4

Indiana Michigan Power Company-Indiana
Annual Internal Energy Requirements and Growth Rates
2001-2031

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requirements GWH	Total Internal Energy Requirements % Growth
Actual												
2001	4,281	---	4,050	---	6,874	---	1,982	---	1,566	---	18,752	---
2002	4,581	7.0	4,144	2.3	7,118	3.5	2,100	6.0	1,654	5.6	19,597	4.5
2003	4,329	-5.5	4,044	-2.4	6,825	-4.1	2,194	4.5	1,852	12.0	19,243	-1.8
2004	4,378	1.1	4,151	2.7	7,036	3.1	2,403	9.5	1,417	-23.5	19,385	0.7
2005	4,738	8.2	4,306	3.7	7,019	-0.2	1,882	-21.7	1,667	17.7	19,612	1.2
2006	4,580	-3.3	4,302	-0.1	7,024	0.1	2,994	59.1	1,642	-1.5	20,542	4.7
2007	4,871	6.3	4,538	5.5	6,959	-0.9	4,009	33.9	1,625	-1.0	22,002	7.1
2008	4,796	-1.5	4,433	-2.3	6,613	-5.0	4,039	0.7	1,654	1.8	21,535	-2.1
2009	4,548	-5.2	4,234	-4.5	5,977	-9.6	4,052	0.3	1,782	7.7	20,593	-4.4
2010	4,806	5.7	4,305	1.7	6,593	10.3	4,261	5.2	1,946	9.2	21,911	6.4
2011*	4,668	-2.9	4,326	0.5	6,667	1.1	4,334	1.7	1,663	-14.5	21,659	-1.2
Forecast												
2012	4,635	-0.7	4,428	2.4	6,937	4.0	4,441	2.5	1,786	7.4	22,228	2.6
2013	4,643	0.2	4,478	1.1	7,224	4.1	4,580	3.1	1,766	-1.2	22,691	2.1
2014	4,612	-0.7	4,448	-0.7	7,119	-1.5	4,640	1.3	1,791	1.5	22,610	-0.4
2015	4,561	-1.1	4,415	-0.7	6,985	-1.9	4,718	1.7	1,800	0.5	22,479	-0.6
2016	4,513	-1.0	4,382	-0.8	6,888	-1.4	4,764	1.0	1,791	-0.5	22,338	-0.6
2017	4,467	-1.0	4,352	-0.7	6,800	-1.3	4,837	1.5	1,764	-1.5	22,221	-0.5
2018	4,417	-1.1	4,319	-0.8	6,710	-1.3	4,883	0.9	1,749	-0.9	22,078	-0.6
2019	4,370	-1.1	4,294	-0.6	6,612	-1.5	4,959	1.6	1,747	-0.1	21,982	-0.4
2020	4,353	-0.4	4,289	-0.1	6,550	-0.9	5,005	0.9	1,738	-0.5	21,935	-0.2
2021	4,364	0.3	4,311	0.5	6,532	-0.3	5,079	1.5	1,723	-0.9	22,009	0.3
2022	4,365	0.0	4,319	0.2	6,511	-0.3	5,125	0.9	1,744	1.2	22,064	0.3
2023	4,376	0.3	4,337	0.4	6,532	0.3	5,147	0.4	1,754	0.6	22,146	0.4
2024	4,396	0.4	4,366	0.7	6,574	0.6	5,171	0.5	1,761	0.4	22,269	0.6
2025	4,421	0.6	4,411	1.0	6,628	0.8	5,197	0.5	1,750	-0.6	22,407	0.6
2026	4,437	0.4	4,443	0.7	6,669	0.6	5,221	0.5	1,774	1.3	22,544	0.6
2027	4,460	0.5	4,482	0.9	6,714	0.7	5,244	0.4	1,779	0.3	22,679	0.6
2028	4,474	0.3	4,509	0.6	6,754	0.6	5,269	0.5	1,819	2.2	22,825	0.6
2029	4,510	0.8	4,563	1.2	6,817	0.9	5,295	0.5	1,788	-1.7	22,973	0.6
2030	4,526	0.3	4,595	0.7	6,864	0.7	5,323	0.5	1,819	1.8	23,126	0.7
2031	4,554	0.6	4,631	0.8	6,914	0.7	5,348	0.5	1,831	0.7	23,279	0.7

*Includes 6 months actual and 6 months forecast data.

Average Annual Growth Rates	Residential	Commercial	Industrial	Other Internal	Losses	Total
2001-2011	0.9	0.7	-0.3	8.1	0.6	1.5
2012-2031	-0.1	0.2	0.0	1.0	0.1	0.2

Indiana Michigan Power Company-Michigan
Annual Internal Energy Requirements and Growth Rates
2001-2031

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2001	1,133	---	723	---	1,040	---	339	---	297	---	3,532	---
2002	1,197	5.7	751	3.9	1,080	3.8	354	4.3	314	5.5	3,695	4.6
2003	1,147	-4.1	733	-2.4	1,054	-2.4	348	-1.6	350	11.5	3,633	-1.7
2004	1,146	-0.2	743	1.2	1,074	1.9	354	1.7	261	-25.2	3,578	-1.5
2005	1,247	8.9	784	5.5	1,071	-0.2	370	4.5	322	23.4	3,795	6.1
2006	1,204	-3.5	766	-2.3	1,025	-4.3	585	58.1	297	-7.9	3,877	2.2
2007	1,261	4.7	835	9.0	1,009	-1.6	610	4.3	296	-0.5	4,010	3.4
2008	1,262	0.1	839	0.5	923	-8.5	590	-3.3	300	1.3	3,914	-2.4
2009	1,218	-3.5	804	-4.1	785	-15.0	576	-2.4	319	6.5	3,702	-5.4
2010	1,277	4.8	816	1.4	852	8.5	626	8.6	347	8.7	3,917	5.8
2011*	1,257	-1.5	807	-1.0	846	-0.6	619	-1.0	323	-7.0	3,853	-1.6
Forecast												
2012	1,255	-0.2	815	0.9	889	5.1	624	0.8	359	11.1	3,941	2.3
2013	1,252	-0.3	826	1.4	873	-1.8	630	1.0	349	-2.7	3,930	-0.3
2014	1,238	-1.1	820	-0.8	848	-2.9	636	0.8	348	-0.1	3,890	-1.0
2015	1,236	-0.2	822	0.2	839	-1.0	641	0.8	350	0.5	3,887	-0.1
2016	1,236	0.0	826	0.6	844	0.6	647	1.0	352	0.5	3,906	0.5
2017	1,240	0.3	835	1.0	857	1.5	654	1.1	352	-0.1	3,936	0.8
2018	1,242	0.2	842	0.9	865	0.9	659	0.7	354	0.6	3,961	0.6
2019	1,244	0.1	848	0.7	865	0.0	661	0.3	357	0.9	3,974	0.3
2020	1,246	0.1	852	0.5	857	-0.9	660	-0.1	358	0.1	3,972	0.0
2021	1,249	0.3	856	0.5	851	-0.7	659	-0.1	354	-0.9	3,970	-0.1
2022	1,252	0.2	859	0.4	849	-0.2	662	0.4	358	1.1	3,980	0.3
2023	1,257	0.4	865	0.7	857	0.9	667	0.7	361	0.8	4,006	0.7
2024	1,264	0.6	872	0.9	869	1.4	671	0.6	364	0.7	4,040	0.8
2025	1,274	0.8	882	1.1	883	1.6	675	0.6	363	-0.3	4,077	0.9
2026	1,281	0.5	890	0.9	897	1.6	679	0.6	368	1.6	4,115	0.9
2027	1,289	0.6	899	1.0	913	1.8	684	0.7	371	0.6	4,155	1.0
2028	1,293	0.4	906	0.8	928	1.7	690	0.8	380	2.5	4,198	1.0
2029	1,305	0.9	918	1.3	948	2.1	696	0.9	375	-1.2	4,242	1.1
2030	1,311	0.4	926	0.9	967	2.0	703	1.0	383	2.1	4,290	1.1
2031	1,320	0.7	936	1.1	990	2.3	710	1.0	388	1.1	4,343	1.2

***Includes 6 months actual and 6 months forecast data.**

Average Annual Growth Rates	Residential	Commercial	Industrial	Other Internal	Losses	Total
2001-2011	1.0	1.1	-2.0	6.2	0.8	0.9
2012-2031	0.3	0.7	0.6	0.7	0.4	0.5

Exhibit 3-6

Indiana Michigan Power Company
Composition of Forecast of Other Internal Sales (GWh)
2012-2031

	Indiana					Michigan				Total Company				
		Internal Sales for Resale					Internal Sales for Resale				Internal Sales for Resale			
Year	Street Lighting	Coop.	Muni.	IMPA	Total	Street Lighting	Muni.	Coop.	Total	Street Lighting	Muni.	Coop.	IMPA	Total
2012	62	1,221	1,434	1,723	4,441	11	613	0	624	74	2,047	1,221	1,723	5,065
2013	62	1,248	1,459	1,811	4,580	11	619	0	630	73	2,078	1,248	1,811	5,210
2014	62	1,261	1,477	1,840	4,640	11	625	0	636	73	2,102	1,261	1,840	5,276
2015	61	1,273	1,486	1,898	4,718	11	630	0	641	72	2,116	1,273	1,898	5,359
2016	60	1,284	1,493	1,927	4,764	11	636	0	647	71	2,129	1,284	1,927	5,411
2017	60	1,294	1,498	1,986	4,837	11	643	0	654	70	2,141	1,294	1,986	5,491
2018	59	1,304	1,505	2,015	4,883	11	648	0	659	70	2,153	1,304	2,015	5,542
2019	58	1,315	1,513	2,074	4,959	11	650	0	661	69	2,163	1,315	2,074	5,620
2020	58	1,325	1,519	2,102	5,005	11	649	0	660	68	2,169	1,325	2,102	5,665
2021	58	1,337	1,524	2,161	5,079	11	649	0	659	68	2,172	1,337	2,161	5,739
2022	58	1,349	1,529	2,190	5,125	11	651	0	662	68	2,180	1,349	2,190	5,787
2023	58	1,359	1,540	2,190	5,147	11	656	0	667	68	2,196	1,359	2,190	5,814
2024	58	1,370	1,554	2,190	5,171	11	660	0	671	68	2,214	1,370	2,190	5,842
2025	58	1,381	1,569	2,190	5,197	11	664	0	675	68	2,233	1,381	2,190	5,872
2026	58	1,391	1,582	2,190	5,221	11	668	0	679	68	2,250	1,391	2,190	5,899
2027	58	1,402	1,595	2,190	5,244	11	673	0	684	68	2,268	1,402	2,190	5,928
2028	58	1,413	1,608	2,190	5,269	11	679	0	690	68	2,287	1,413	2,190	5,958
2029	58	1,425	1,623	2,190	5,295	11	685	0	696	69	2,308	1,425	2,190	5,991
2030	58	1,438	1,637	2,190	5,323	11	692	0	703	69	2,329	1,438	2,190	6,026
2031	58	1,450	1,650	2,190	5,348	11	699	0	710	69	2,350	1,450	2,190	6,058

AEP System - East Zone
Annual Internal Energy Requirements and Growth Rates
2001-2031

Year	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2001	32,765	---	25,656	---	40,588	---	4,957	---	8,516	---	112,482	---
2002	35,045	7.0	26,564	3.5	40,734	0.4	5,054	1.9	9,055	6.3	116,452	3.5
2003	34,352	-2.0	26,568	0.0	39,513	-3.0	5,099	0.9	9,257	2.2	114,791	-1.4
2004	34,921	1.7	26,966	1.5	40,986	3.7	4,642	-9.0	9,417	1.7	116,932	1.9
2005	37,067	6.1	28,201	4.6	41,967	2.4	3,696	-20.4	10,144	7.7	121,075	3.5
2006	35,662	-3.8	28,056	-0.5	42,663	1.7	5,449	47.4	10,331	1.8	122,161	0.9
2007	30,283	-15.1	29,649	5.7	46,358	8.7	6,951	27.6	10,144	-1.8	123,386	1.0
2008	37,321	23.2	29,194	-1.5	47,278	2.0	7,472	7.5	10,329	1.8	131,594	6.7
2009	36,186	-3.0	28,490	-2.4	39,243	-17.0	7,455	-0.2	9,628	-6.8	121,002	-8.0
2010	38,446	6.2	29,113	2.2	41,344	5.4	7,304	-2.0	9,917	3.0	126,125	4.2
2011*	37,016	-3.7	28,636	-1.6	42,903	3.8	7,312	0.1	10,007	0.9	125,874	-0.2
Forecast												
2012	36,723	-0.8	28,889	0.9	44,475	3.7	7,444	1.8	9,585	-4.2	127,117	1.0
2013	36,721	0.0	29,147	0.9	45,147	1.5	7,606	2.2	9,539	-0.5	128,161	0.8
2014	36,659	-0.2	29,183	0.1	44,951	-0.4	7,699	1.2	9,563	0.3	128,055	-0.1
2015	36,580	-0.2	29,253	0.2	44,667	-0.6	7,808	1.4	9,581	0.2	127,890	-0.1
2016	36,477	-0.3	29,354	0.3	44,554	-0.3	7,881	0.9	9,619	0.4	127,885	0.0
2017	36,403	-0.2	29,474	0.4	44,515	-0.1	7,982	1.3	9,548	-0.7	127,921	0.0
2018	36,367	-0.1	29,624	0.5	44,522	0.0	8,057	0.9	9,537	-0.1	128,107	0.1
2019	36,303	-0.2	29,742	0.4	44,482	-0.1	8,162	1.3	9,571	0.4	128,260	0.1
2020	36,261	-0.1	29,842	0.3	44,502	0.0	8,236	0.9	9,608	0.4	128,449	0.1
2021	36,377	0.3	30,069	0.8	44,679	0.4	8,340	1.3	9,538	-0.7	129,004	0.4
2022	36,486	0.3	30,242	0.6	44,767	0.2	8,415	0.9	9,654	1.2	129,564	0.4
2023	36,667	0.5	30,415	0.6	44,887	0.3	8,466	0.6	9,704	0.5	130,139	0.4
2024	36,908	0.7	30,580	0.5	45,007	0.3	8,520	0.6	9,759	0.6	130,774	0.5
2025	37,186	0.8	30,828	0.8	45,181	0.4	8,575	0.6	9,704	-0.6	131,473	0.5
2026	37,458	0.7	31,064	0.8	45,317	0.3	8,627	0.6	9,830	1.3	132,298	0.6
2027	37,781	0.9	31,342	0.9	45,583	0.6	8,682	0.6	9,887	0.6	133,275	0.7
2028	38,060	0.7	31,576	0.7	45,846	0.6	8,739	0.7	10,118	2.3	134,339	0.8
2029	38,436	1.0	31,904	1.0	46,180	0.7	8,801	0.7	9,993	-1.2	135,313	0.7
2030	38,724	0.7	32,142	0.7	46,514	0.7	8,863	0.7	10,132	1.4	136,375	0.8
2031	39,090	0.9	32,430	0.9	46,850	0.7	8,924	0.7	10,200	0.7	137,494	0.8

***Includes 6 months actual and 6 months forecast data.**

Average Annual Growth Rates												
2001-2011		1.2		1.1		0.6		4.0		1.6		1.1
2012-2031		0.3		0.6		0.3		1.0		0.3		0.4

Indiana Michigan Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2001-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2001	08/08/01	4,232	---	12/31/00	3,393	---	4,232	---	22,284	---	60.1
2002	07/22/02	4,303	1.7	03/04/02	3,258	-4.0	4,303	1.7	23,293	4.5	61.8
2003	08/21/03	4,223	-1.9	01/07/03	3,683	13.0	4,223	-1.9	22,876	-1.8	61.8
2004	07/22/04	4,016	-4.9	01/22/04	3,465	-5.9	4,016	-4.9	22,962	0.4	65.1
2005	08/09/05	4,193	4.4	01/28/05	3,465	0.0	4,193	4.4	23,407	1.9	63.7
2006	07/31/06	4,650	10.9	12/08/05	3,537	2.1	4,650	10.9	24,419	4.3	59.9
2007	08/07/07	4,528	-2.6	02/06/07	3,945	11.5	4,528	-2.6	26,013	6.5	65.6
2008	07/31/08	4,264	-5.8	01/25/08	3,875	-1.8	4,264	-5.8	25,448	-2.2	67.9
2009	06/25/09	4,262	0.0	01/15/09	3,728	-3.8	4,262	0.0	24,296	-4.5	65.1
2010	07/23/10	4,474	5.0	12/10/09	3,858	3.5	4,474	5.0	25,828	6.3	65.9
2011*	07/21/11	4,837	8.1	12/13/10	3,785	-1.9	4,837	8.1	25,512	-1.2	60.0
Forecast											
2012		4,527	-6.4		3,932	3.9	4,527	-6.4	26,169	2.6	66.0
2013		4,613	1.9		4,007	1.9	4,613	1.9	26,621	1.7	65.9
2014		4,597	-0.4		3,988	-0.5	4,597	-0.4	26,500	-0.5	65.8
2015		4,579	-0.4		3,963	-0.6	4,579	-0.4	26,366	-0.5	65.7
2016		4,558	-0.5		3,930	-0.8	4,558	-0.5	26,244	-0.5	65.7
2017		4,560	0.0		3,915	-0.4	4,560	0.0	26,158	-0.3	65.5
2018		4,550	-0.2		3,894	-0.5	4,550	-0.2	26,039	-0.5	65.3
2019		4,545	-0.1		3,878	-0.4	4,545	-0.1	25,956	-0.3	65.2
2020		4,536	-0.2		3,856	-0.6	4,536	-0.2	25,907	-0.2	65.2
2021		4,563	0.6		3,874	0.5	4,563	0.6	25,978	0.3	65.0
2022		4,580	0.4		3,882	0.2	4,580	0.4	26,044	0.3	64.9
2023		4,605	0.5		3,888	0.2	4,605	0.5	26,152	0.4	64.8
2024		4,628	0.5		3,898	0.3	4,628	0.5	26,308	0.6	64.9
2025		4,676	1.0		3,935	0.9	4,676	1.0	26,484	0.7	64.7
2026		4,713	0.8		3,959	0.6	4,713	0.8	26,659	0.7	64.6
2027		4,750	0.8		3,983	0.6	4,750	0.8	26,834	0.7	64.5
2028		4,780	0.6		4,000	0.4	4,780	0.6	27,023	0.7	64.5
2029		4,828	1.0		4,029	0.7	4,828	1.0	27,215	0.7	64.4
2030		4,870	0.9		4,057	0.7	4,870	0.9	27,416	0.7	64.3
2031		4,912	0.9		4,088	0.8	4,912	0.9	27,622	0.8	64.2

***Total energy requirements reflect 6 months actual and 6 months forecast data. The summer peak reflects actual peak through August.**

AEP System - East Zone
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2001-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2001	08/08/01	20,218	---	01/03/01	18,634	---	20,218	---	112,482	---	63.5
2002	08/01/02	20,402	0.9	02/05/02	17,909	-3.9	20,402	0.9	116,452	3.5	65.2
2003	08/21/03	19,688	-3.5	01/23/03	19,454	8.6	19,688	-3.5	114,791	-1.4	66.6
2004	08/03/04	19,145	-2.8	01/23/04	18,958	-2.5	19,706	0.1	116,932	1.9	67.6
2005	07/26/05	20,855	8.9	01/18/05	19,877	4.8	20,855	5.8	121,075	3.5	66.3
2006	08/02/06	21,950	5.3	12/20/05	19,649	-1.1	21,950	5.3	122,161	0.9	63.5
2007	08/08/07	22,429	2.2	02/06/07	21,734	10.6	22,429	2.2	130,688	7.0	66.5
2008	06/09/08	21,635	-3.5	01/25/08	22,005	1.2	22,005	-1.9	131,594	0.7	68.1
2009	08/10/09	19,901	-8.0	01/16/09	22,295	1.3	22,295	1.3	121,002	-8.0	62.0
2010	07/23/10	21,259	6.8	01/11/10	20,360	-8.7	21,259	-4.6	126,125	4.2	67.7
2011*	07/21/11	22,200	4.4	12/14/10	20,605	1.2	22,200	4.4	125,874	-0.2	64.5
Forecast											
2012		21,264	-4.2		20,895	1.4	21,264	-4.2	127,117	1.0	68.2
2013		21,474	1.0		21,172	1.3	21,474	1.0	128,161	0.8	68.1
2014		21,508	0.2		21,172	0.0	21,508	0.2	128,055	-0.1	68.0
2015		21,531	0.1		21,151	-0.1	21,531	0.1	127,890	-0.1	67.8
2016		21,521	0.0		21,083	-0.3	21,521	0.0	127,885	0.0	67.8
2017		21,585	0.3		21,065	-0.1	21,585	0.3	127,921	0.0	67.7
2018		21,668	0.4		21,096	0.1	21,668	0.4	128,107	0.1	67.5
2019		21,750	0.4		21,136	0.2	21,750	0.4	128,260	0.1	67.3
2020		21,780	0.1		21,082	-0.3	21,780	0.1	128,449	0.1	67.3
2021		21,949	0.8		21,275	0.9	21,949	0.8	129,004	0.4	67.1
2022		22,076	0.6		21,370	0.4	22,076	0.6	129,564	0.4	67.0
2023		22,175	0.4		21,365	0.0	22,175	0.4	130,139	0.4	67.0
2024		22,275	0.5		21,390	0.1	22,275	0.5	130,774	0.5	67.0
2025		22,492	1.0		21,600	1.0	22,492	1.0	131,473	0.5	66.7
2026		22,672	0.8		21,748	0.7	22,672	0.8	132,298	0.6	66.6
2027		22,874	0.9		21,903	0.7	22,874	0.9	133,275	0.7	66.5
2028		23,043	0.7		21,997	0.4	23,043	0.7	134,339	0.8	66.6
2029		23,258	0.9		22,133	0.6	23,258	0.9	135,313	0.7	66.4
2030		23,481	1.0		22,306	0.8	23,481	1.0	136,375	0.8	66.3
2031		23,712	1.0		22,498	0.9	23,712	1.0	137,494	0.8	66.2

*Total energy requirements reflect 6 months actual and 6 months forecast data. The summer peak reflects actual peak through August.

Exhibit 3-10

AEP System - East Zone
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

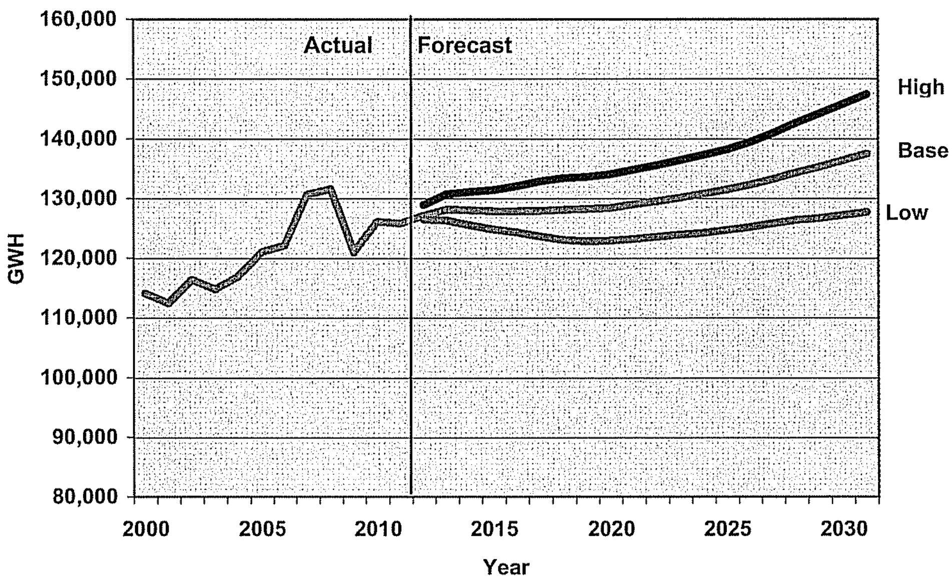
	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2012	20,793	20,895	21,189	21,161	21,264	21,563	126,497	127,117	128,904
2013	20,873	21,172	21,599	21,171	21,474	21,906	126,355	128,161	130,745
2014	20,753	21,172	21,681	21,081	21,508	22,025	125,517	128,055	131,135
2015	20,642	21,151	21,735	21,014	21,531	22,126	124,816	127,890	131,421
2016	20,498	21,083	21,774	20,924	21,521	22,226	124,336	127,885	132,076
2017	20,366	21,065	21,879	20,868	21,585	22,420	123,672	127,921	132,865
2018	20,266	21,096	21,973	20,815	21,668	22,568	123,066	128,107	133,430
2019	20,246	21,136	22,023	20,834	21,750	22,663	122,861	128,260	133,644
2020	20,181	21,082	22,001	20,850	21,780	22,729	122,960	128,449	134,046
2021	20,321	21,275	22,235	20,965	21,949	22,939	123,217	129,004	134,823
2022	20,382	21,370	22,360	21,055	22,076	23,099	123,574	129,564	135,567
2023	20,352	21,365	22,398	21,123	22,175	23,246	123,965	130,139	136,426
2024	20,321	21,390	22,454	21,162	22,275	23,383	124,237	130,774	137,279
2025	20,494	21,600	22,706	21,341	22,492	23,644	124,745	131,473	138,210
2026	20,584	21,748	22,922	21,459	22,672	23,896	125,216	132,298	139,440
2027	20,685	21,903	23,160	21,601	22,874	24,187	125,863	133,275	140,925
2028	20,696	21,997	23,358	21,680	23,043	24,469	126,389	134,339	142,649
2029	20,726	22,133	23,592	21,780	23,258	24,791	126,710	135,313	144,229
2030	20,801	22,306	23,841	21,896	23,481	25,097	127,170	136,375	145,758
2031	20,903	22,498	24,126	22,031	23,712	25,428	127,745	137,494	147,440
Average Annual Growth Rate % - 2010-2029	0.0	0.4	0.7	0.2	0.6	0.9	0.1	0.4	0.7

Indiana Michigan Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2012	3,913	3,932	3,987	4,505	4,527	4,590	26,041	26,169	26,537
2013	3,950	4,007	4,087	4,548	4,613	4,706	26,246	26,621	27,158
2014	3,909	3,988	4,084	4,506	4,597	4,707	25,974	26,500	27,137
2015	3,868	3,963	4,072	4,469	4,579	4,706	25,733	26,366	27,094
2016	3,821	3,930	4,058	4,432	4,558	4,708	25,516	26,244	27,104
2017	3,785	3,915	4,066	4,408	4,560	4,736	25,289	26,158	27,169
2018	3,741	3,894	4,056	4,371	4,550	4,739	25,014	26,039	27,120
2019	3,714	3,878	4,040	4,354	4,545	4,736	24,863	25,956	27,046
2020	3,691	3,856	4,024	4,342	4,536	4,733	24,800	25,907	27,036
2021	3,701	3,874	4,049	4,358	4,563	4,768	24,813	25,978	27,150
2022	3,702	3,882	4,062	4,369	4,580	4,793	24,840	26,044	27,251
2023	3,703	3,888	4,075	4,386	4,605	4,827	24,912	26,152	27,416
2024	3,703	3,898	4,092	4,396	4,628	4,858	24,993	26,308	27,617
2025	3,733	3,935	4,136	4,437	4,676	4,916	25,129	26,484	27,841
2026	3,747	3,959	4,173	4,461	4,713	4,968	25,232	26,659	28,098
2027	3,762	3,983	4,212	4,485	4,750	5,022	25,342	26,834	28,374
2028	3,764	4,000	4,248	4,497	4,780	5,075	25,424	27,023	28,695
2029	3,773	4,029	4,294	4,521	4,828	5,146	25,485	27,215	29,008
2030	3,783	4,057	4,336	4,541	4,870	5,205	25,566	27,416	29,303
2031	3,798	4,088	4,384	4,564	4,912	5,268	25,663	27,622	29,620
Average Annual Growth Rate % - 2010-2029	-0.2	0.2	0.5	0.1	0.4	0.7	-0.1	0.3	0.6

AEP System - East Zone
Range of Forecasts

Internal Energy Requirements



Summer Peak Demand

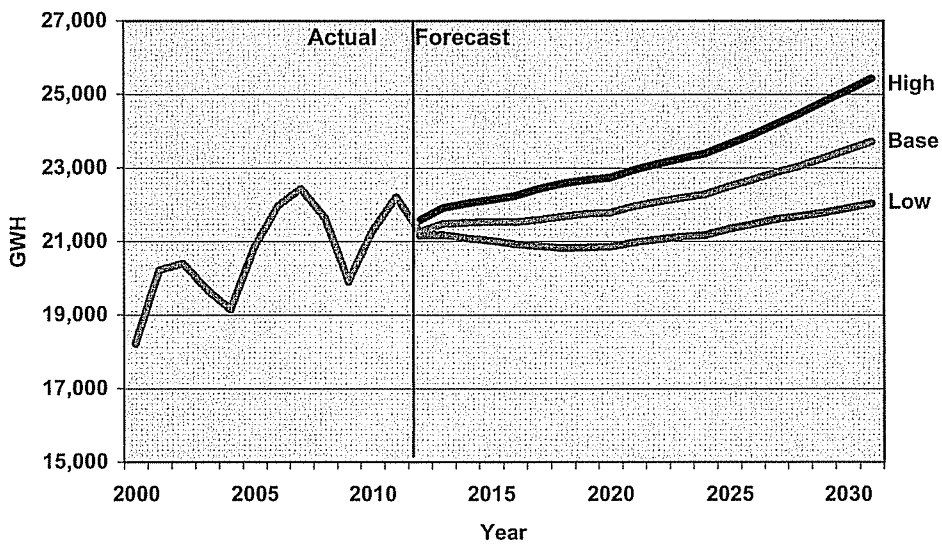
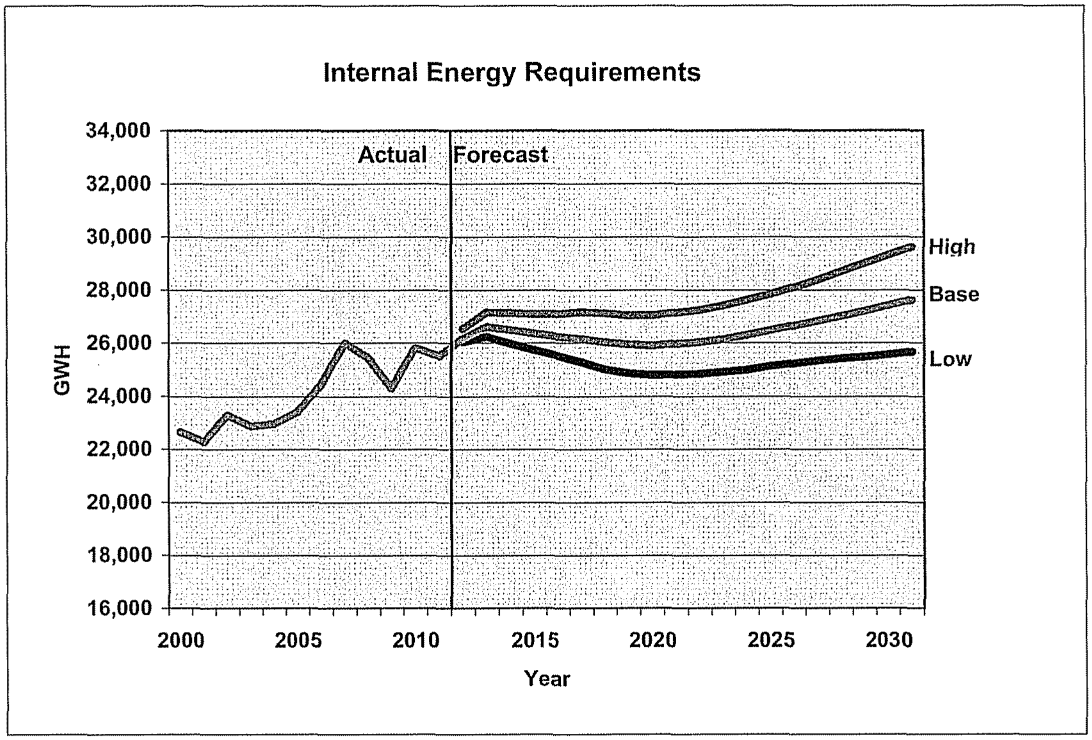
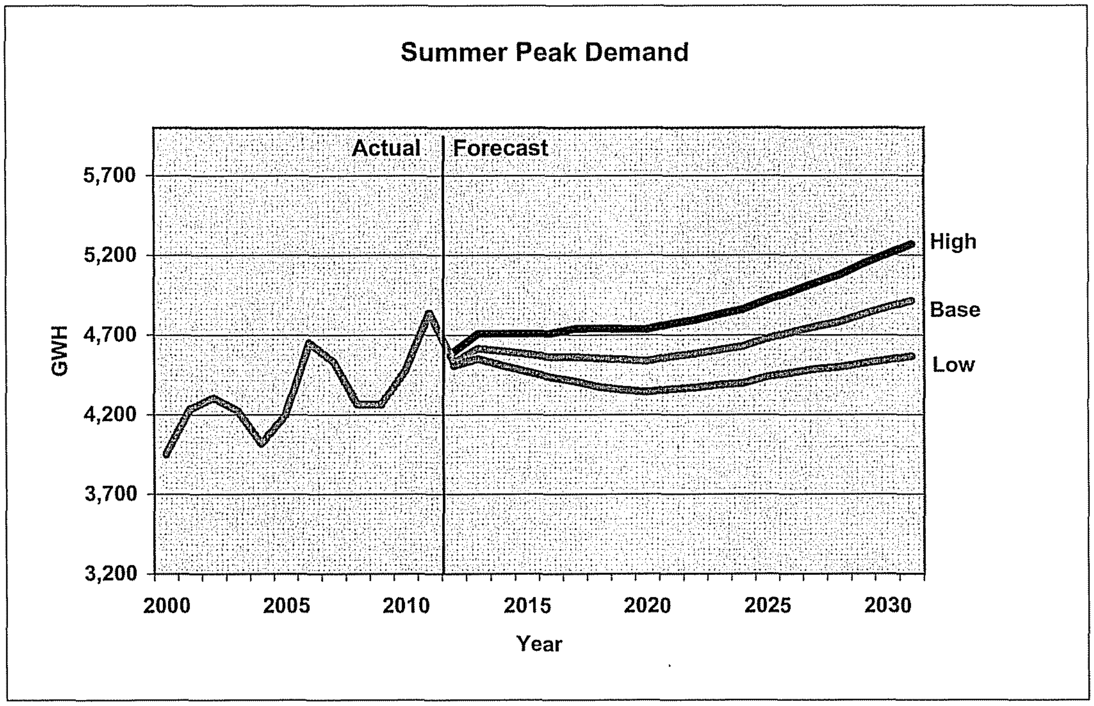


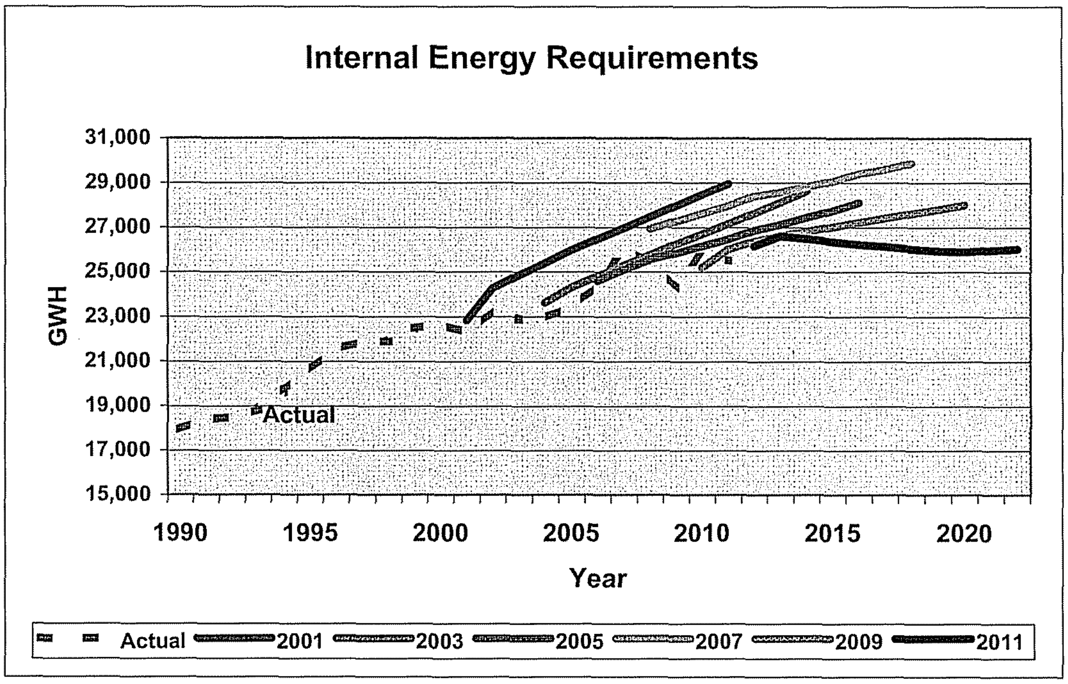
Exhibit 3-13

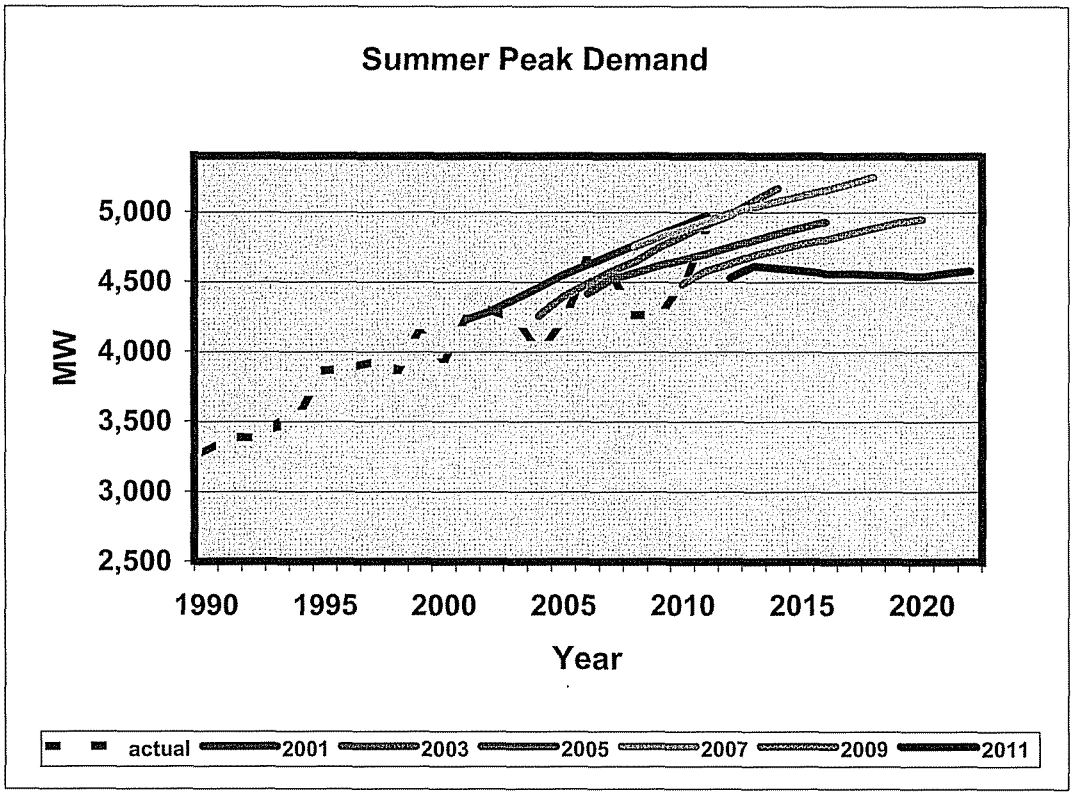
Indiana Michigan Power Company
Range of Forecasts



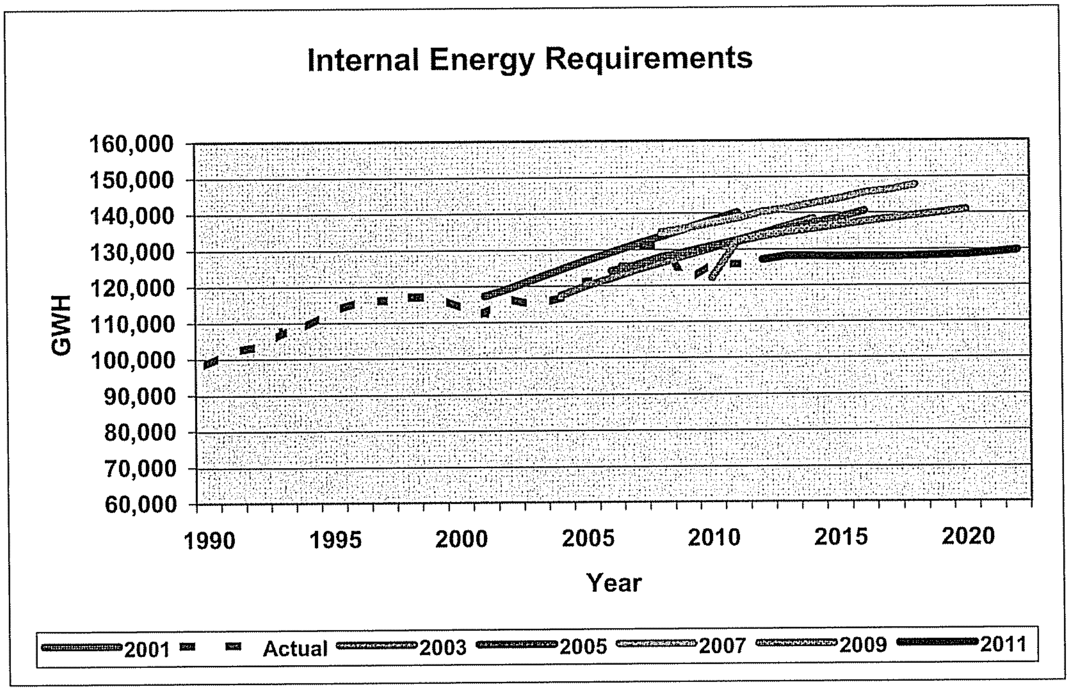


INDIANA MICHIGAN POWER COMPANY
COMPARISON OF FORECASTS





AEP System - East Zone
COMPARISON OF FORECASTS



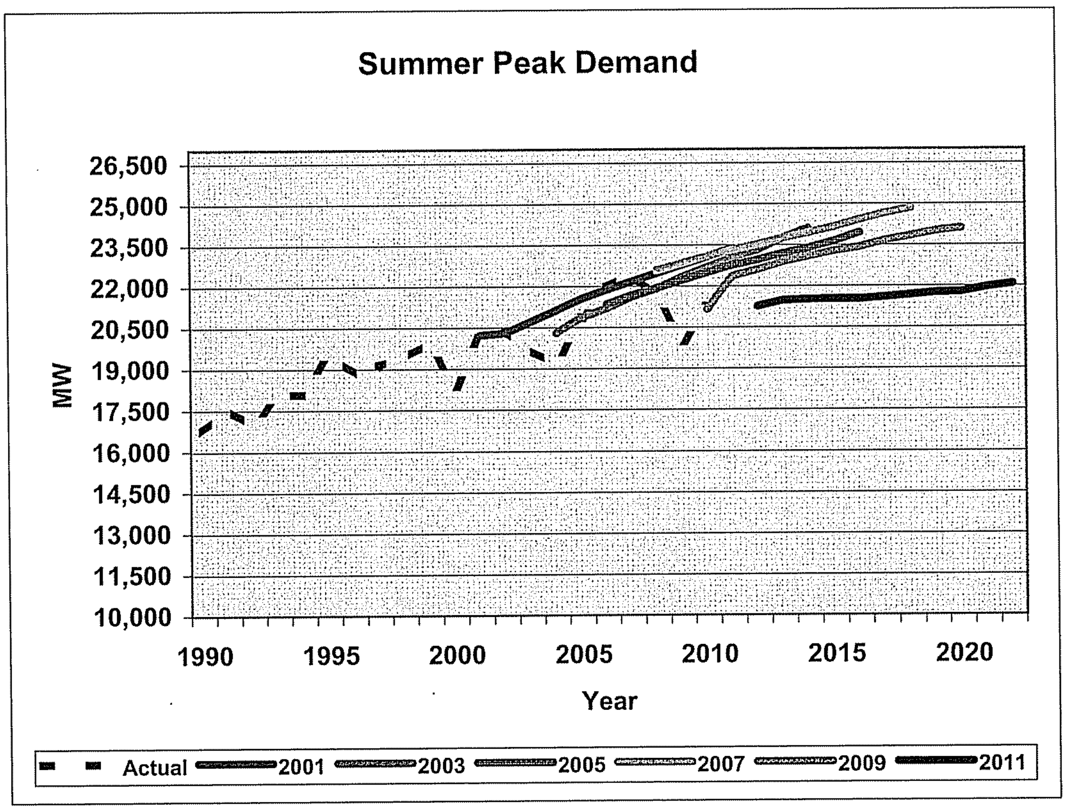
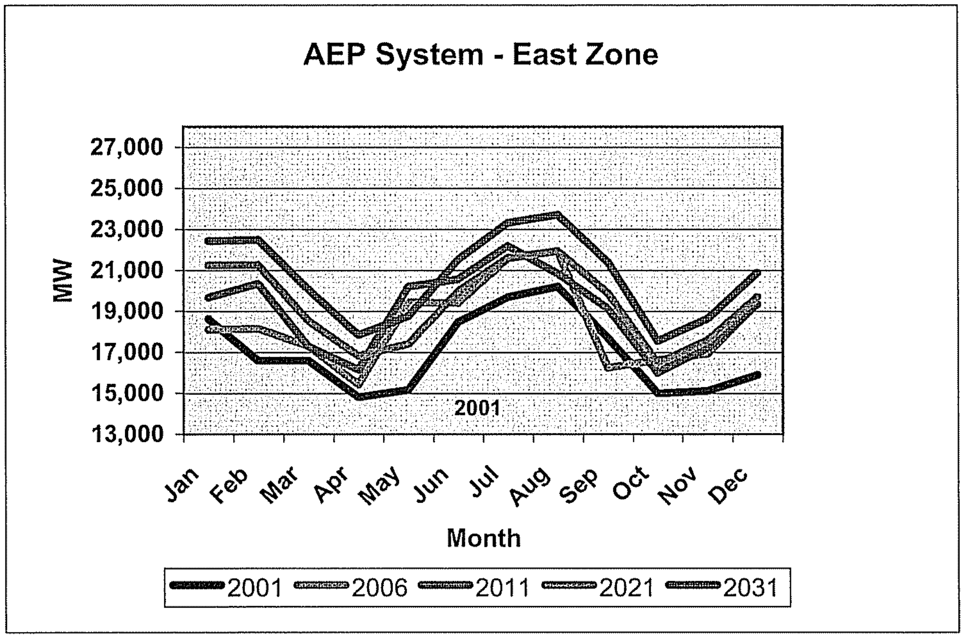


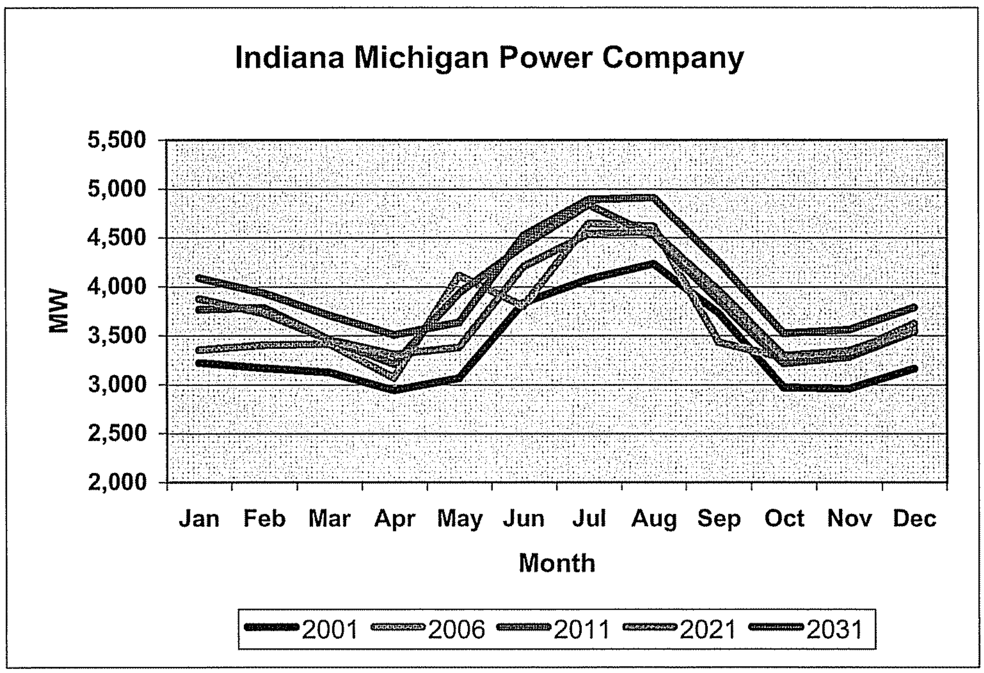
Exhibit 3-16

Indiana Michigan Power Company and AEP System - East Zone
Recorded and Weather Normalized Peak Load (MW) and Energy (GWh)
2001-2010

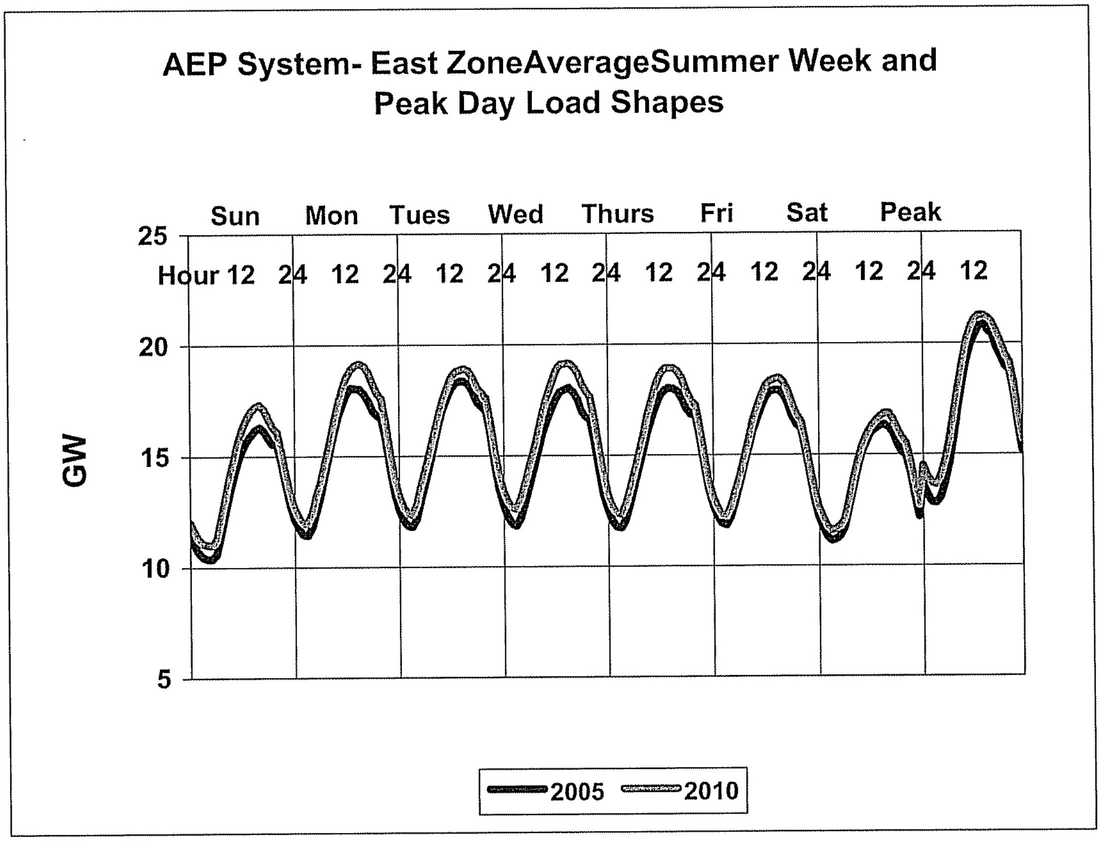
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Indiana Michigan Power Company											
A.	**Peak Load - Summer**										
	1. Recorded	4,232	4,303	4,223	4,016	4,193	4,650	4,528	4,264	4,262	4,474
	2. Weather - Normalized	4,017	4,194	4,177	4,176	4,225	4,373	4,544	4,400	3,943	4,404
B.	**Peak Load - Preceding Winter**										
	1. Recorded	3,393	3,258	3,683	3,465	3,465	3,537	3,945	3,875	3,728	3,858
	2. Weather - Normalized	3,438	3,165	3,596	3,550	3,548	3,383	3,745	3,889	3,713	3,647
C.	**Energy**										
	1. Recorded	22,284	23,293	22,876	22,962	23,407	24,419	26,013	25,448	24,296	25,828
	2. Weather - Normalized	22,365	23,030	23,137	23,266	23,111	24,764	25,774	25,488	24,644	25,365
AEP System - East Zone											
A.	**Peak Load - Summer**										
	1. Recorded	20,218	20,402	19,688	19,145	20,855	21,950	22,429	21,635	19,901	21,259
	2. Weather - Normalized	19,385	19,623	20,055	19,719	20,520	20,611	21,654	20,434	20,328	20,918
B.	**Peak Load - Preceding Winter**										
	1. Recorded	18,634	17,909	19,454	18,958	19,877	19,649	21,734	22,005	22,295	20,360
	2. Weather - Normalized	18,949	18,278	19,136	19,403	19,624	18,642	20,064	21,157	20,814	20,228
C.	**Energy**										
	1. Recorded	112,482	116,452	114,791	116,932	121,075	122,161	130,688	131,594	121,002	126,125
	2. Weather - Normalized	113,484	115,135	115,813	117,890	119,754	123,807	128,824	131,414	121,964	123,320

AEP System - East Zone and Indiana Michigan Power Company
Profiles of Monthly Peak Internal Demands
2001, 2006, 2011* (Actual)
2021 and 2031





***Data for 2011 include eight months actual and four month forecast.**


AEP System- East ZoneAverageSummer Week and Peak Day Load Shapes
Sun Mon Tues Wed Thurs Fri Sat Peak
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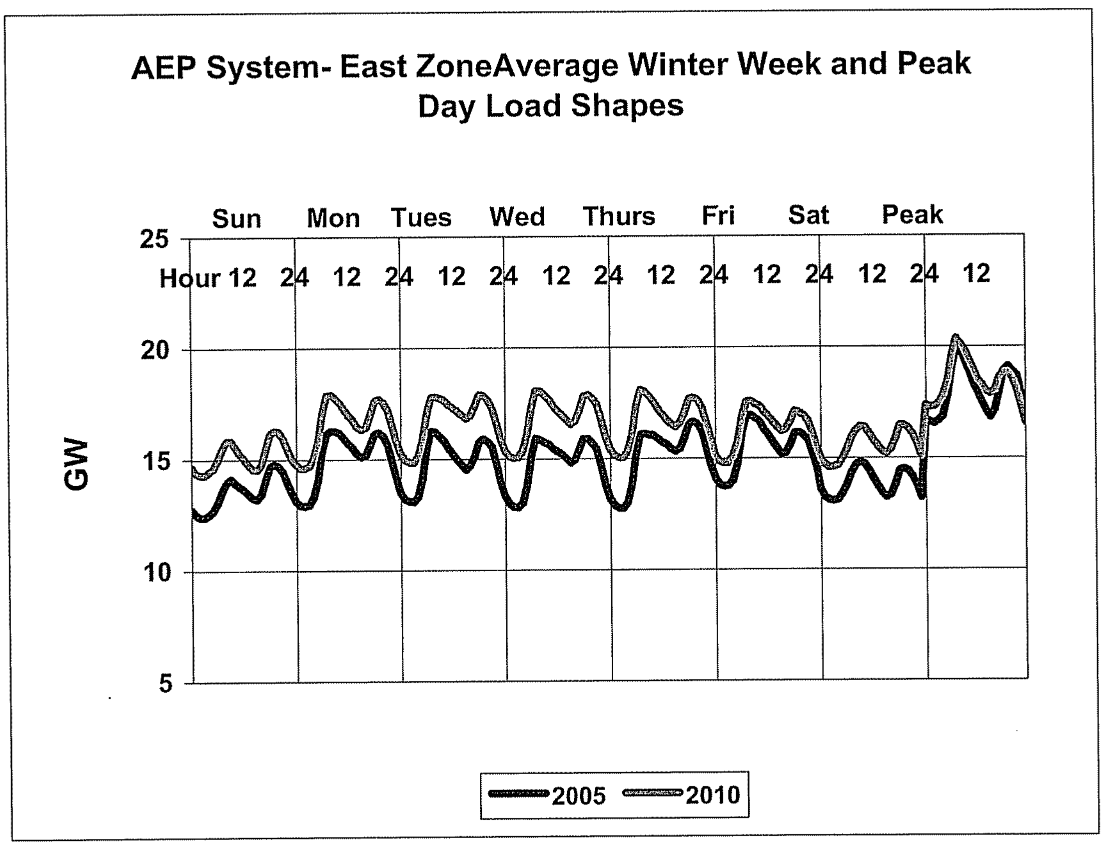
AEP System- East ZoneAverage Winter Week and Peak Day Load Shapes
Sun Mon Tues Wed Thurs Fri Sat Peak
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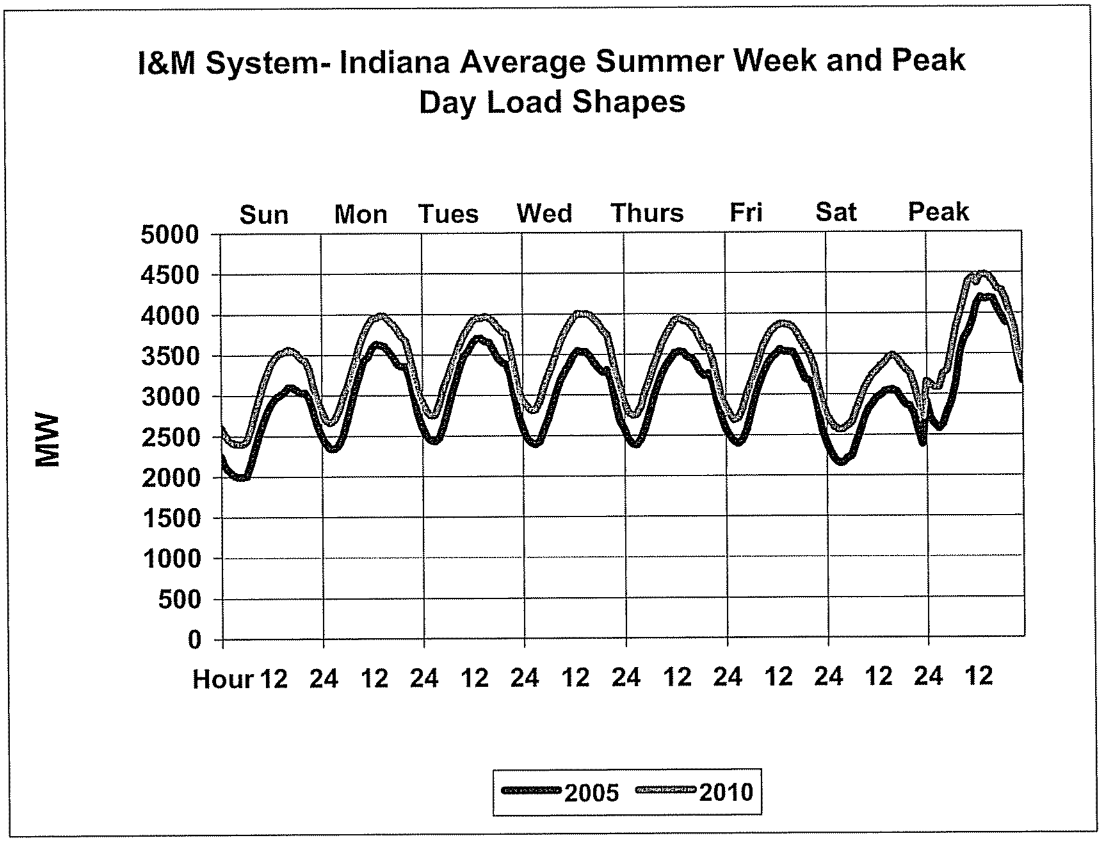
I&M System- Indiana Average Summer Week and Peak Day Load Shapes
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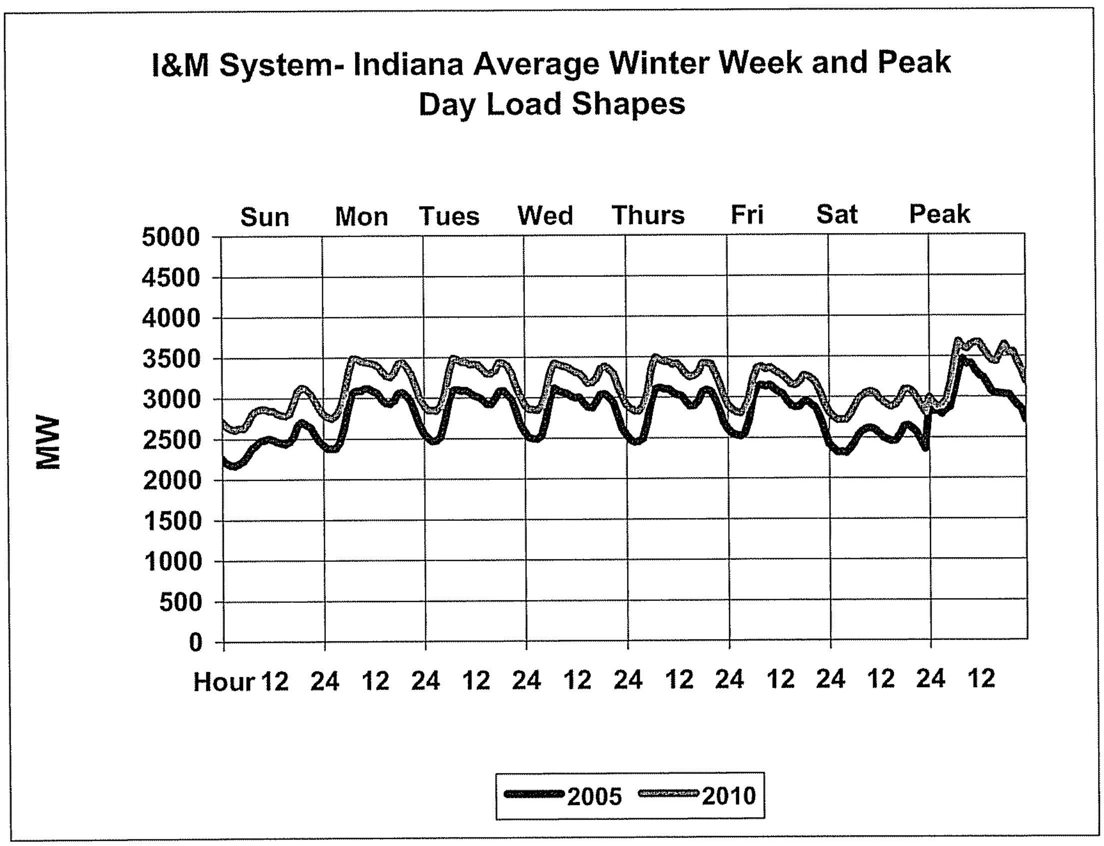
I&M System- Indiana Average Winter Week and Peak Day Load Shapes
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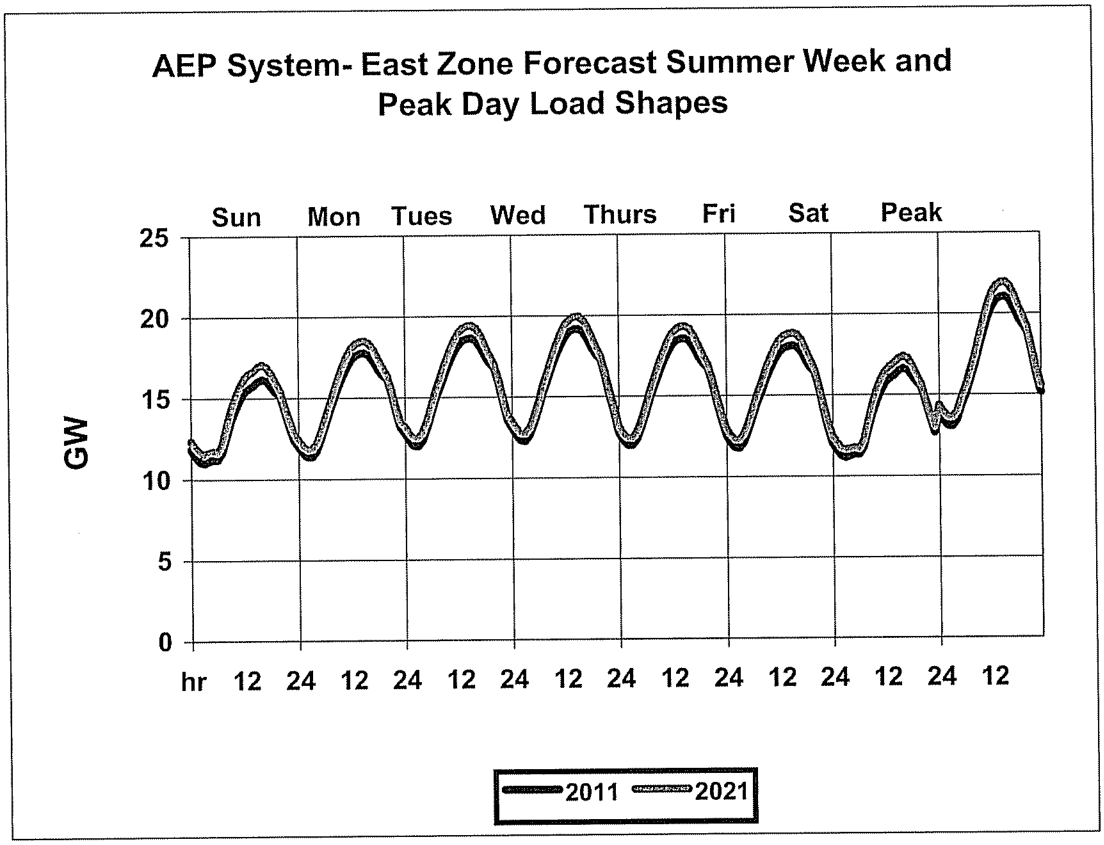
AEP System- East Zone Forecast Summer Week and Peak Day Load Shapes
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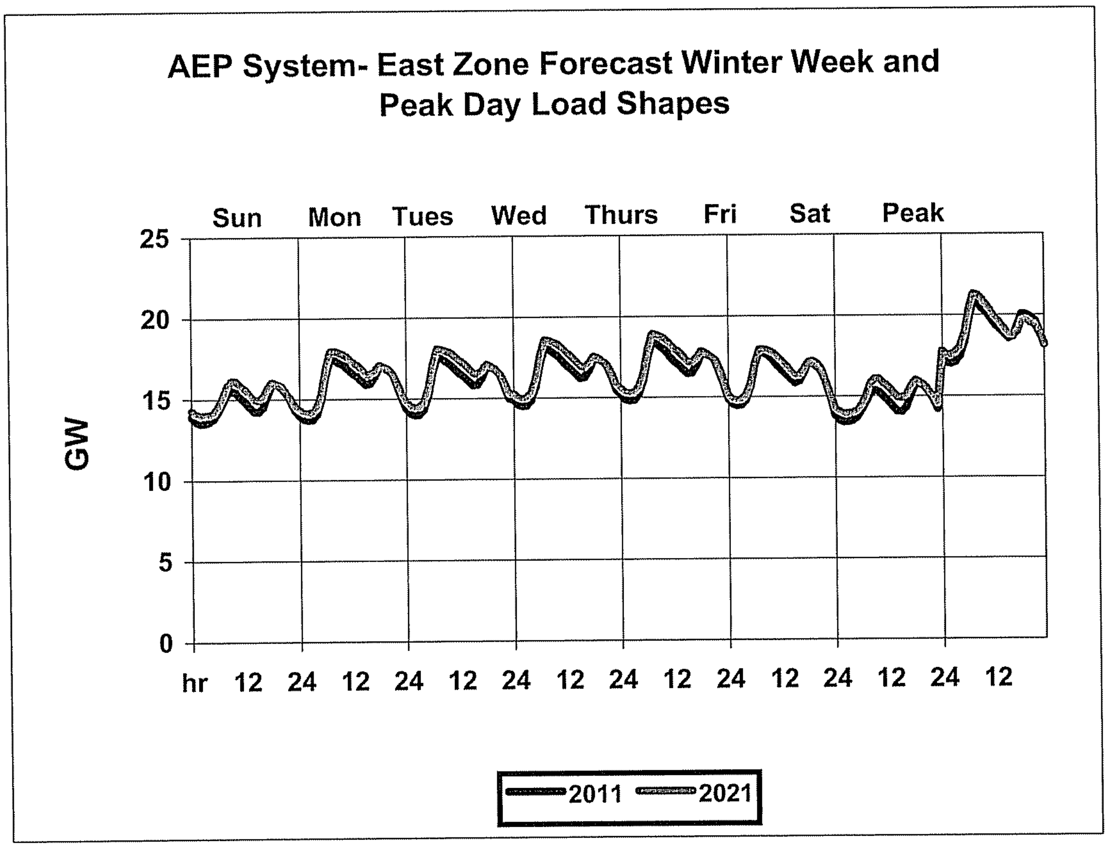
AEP System- East Zone Forecast Winter Week and Peak Day Load Shapes
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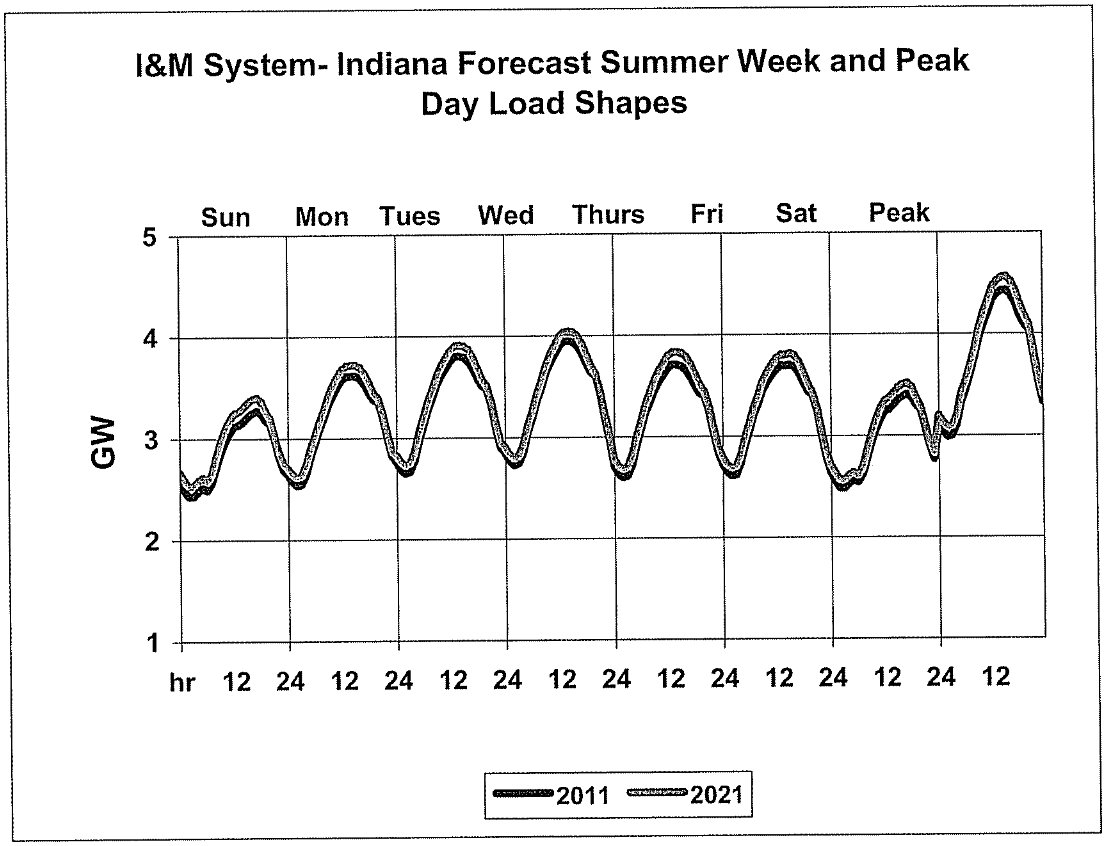
2011 2021


I&M System- Indiana Forecast Summer Week and Peak Day Load Shapes
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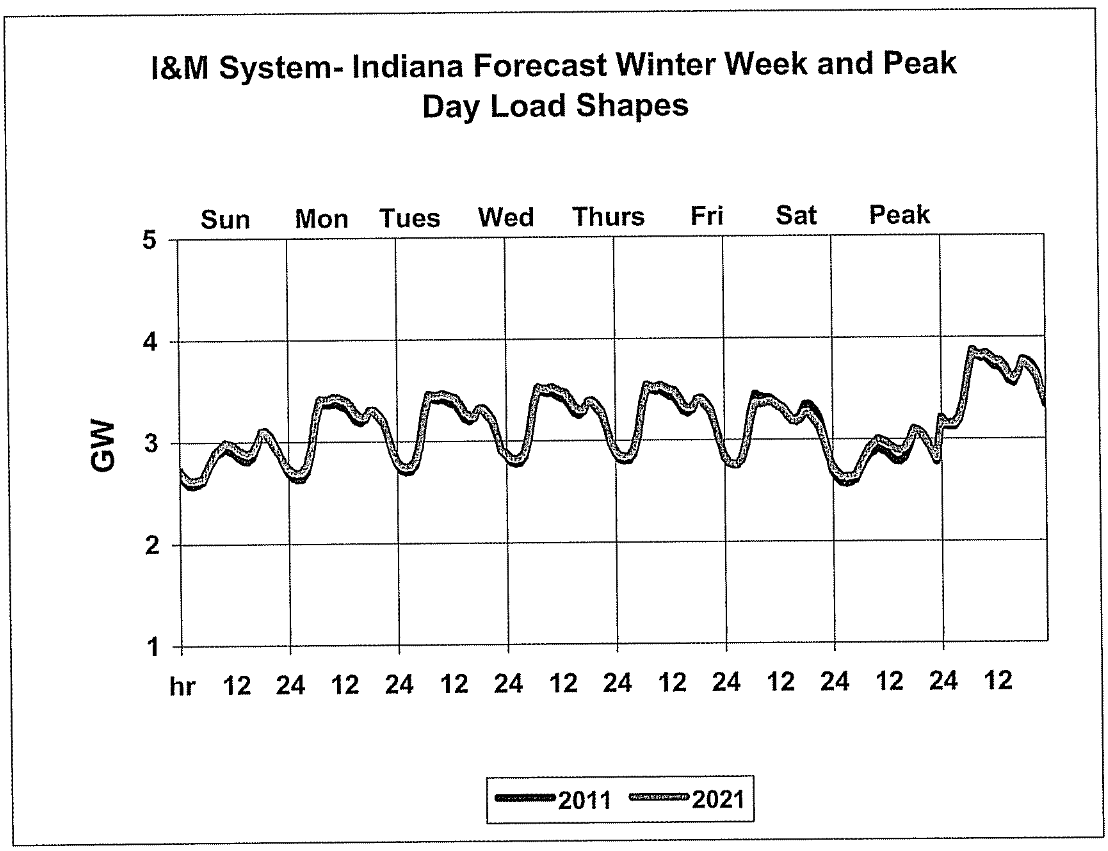
I&M System- Indiana Forecast Winter Week and Peak Day Load Shapes
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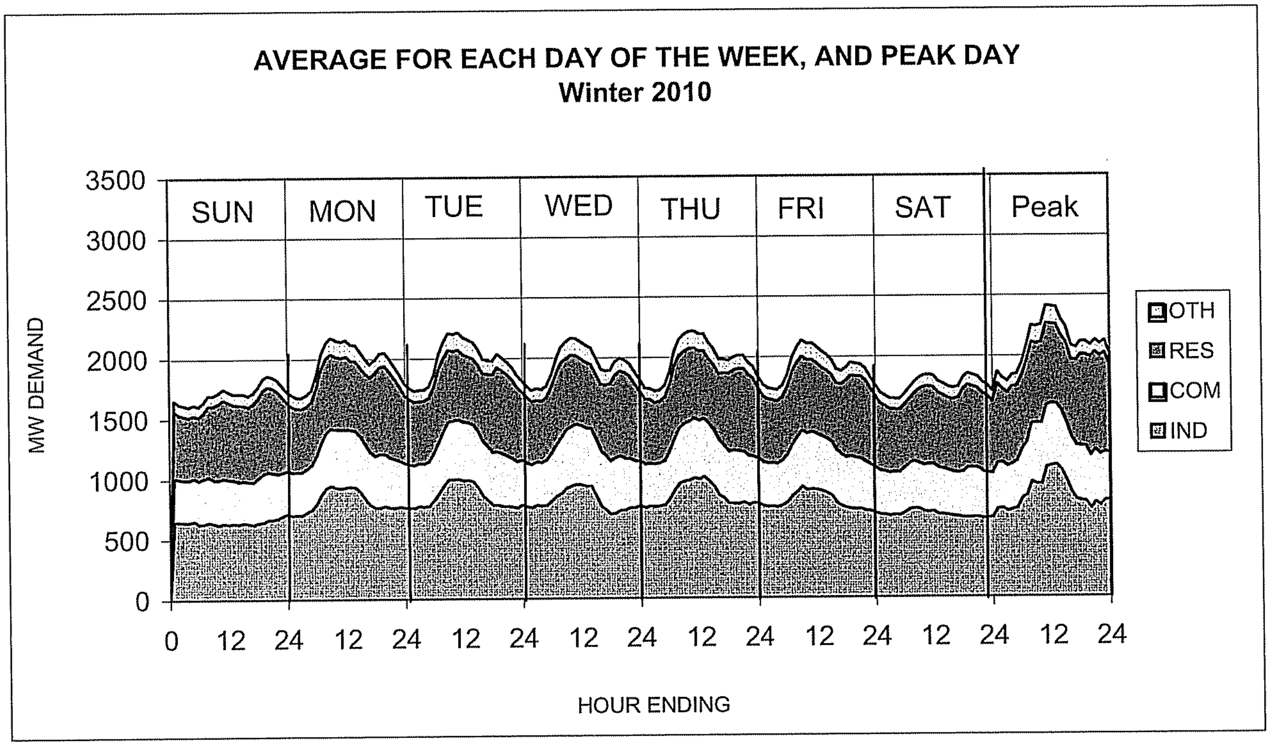
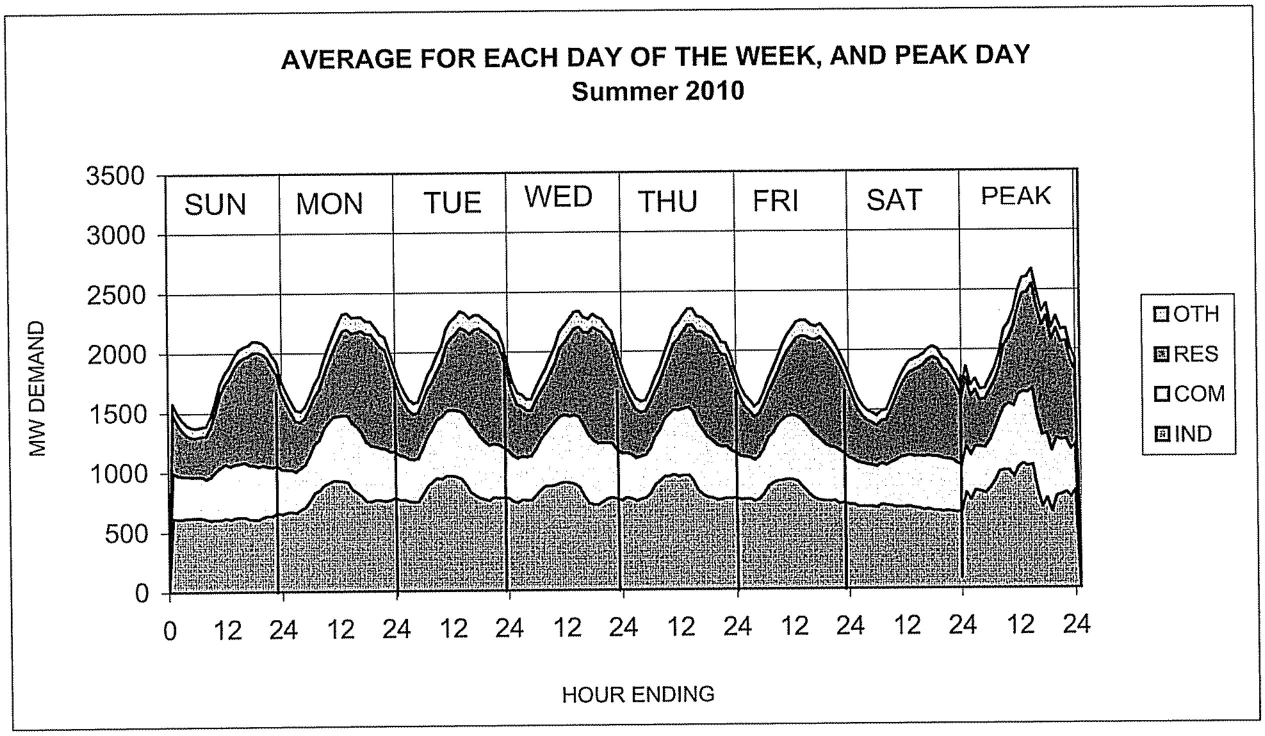
2011
2021

I&M - INDIANA JURISDICTION HOURLY DEMAND BY CLASS





INDIANA MICHIGAN POWER COMPANY LOAD FORECAST
DATA SOURCES OUTSIDE THE COMPANY

DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1984-2010	NOAA (1) Weather Bank	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/84-9/10	NOAA (1) Weather Bank	
Gross Regional Product, Manufacturing	Quarterly	U. S.	1984-2040	Moody's Analytics (2)	None
CPI-All Urban Wage Earners	Quarterly	U. S.	1975:1-2040:4	Moody's Analytics (2)	
U.S. Gas Prices, U.S. Gas Consumption	Annually	U.S.	1975-2035	DOE/EIA (6)	Growth rate historical da
Index of Producer Prices-Industrial Commodities	Quarterly	U. S.	1975:1-2040:4	Moody's Analytics (2)	Annual avei long-term m
Residential Appliance Efficiencies, Saturation Trends, Housing Size	Annual, Monthly	East North Central Census Region	1980-2035	DOE via Itron(7) Itron	Extrapolate trends to Cc
Commericial Equipment Efficiencies, Saturations Square-Footage	Annual, Monthly	East North Central Census Region	1980-2035	DOE via Itron(8) Itron	Extrapolate
U. S., Indiana and Michigan Natural Gas Prices by Sector	Annually	U. S.	1973-2009	DOE/EIA (4)	None
Gross Regional Product	Quarterly	Selected Indiana and Michigan Counties	1975-2040	Moody's Analytics (5)	None
Employment (Total and Selected Sectors), Personal Income and Population	Quarterly	Selected Indiana and Michigan Counties	1975-2040	Moody's Analytics (5)	None

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) October 2010 Forecast, Moody's Analytics
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2010
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly" and "Natrual Gas Annual," Selected Issues.
(5) October 2010 Regional Forecast, Moody's Analytics
(6) U.S. Department of Energy/Energy Information Administration "Annual Energy Outlook 2010 with Projections to 2035" April 2010

AEP SYSTEM - EAST ZONE
AND INDIANA MICHIGAN POWER COMPANY
GENERATING CAPACITY IN SERVICE (A)

			CAPABILITY - MW			
			AEP SYSTEM		I&M (B)	
PLANT	**UNITS**	**NOTES**	**Winter** (H)	**Summer** (G)	**Winter** (H)	**Summer** (G)
John E. Amos	1-3		2,900	2,865	-	-
W. C. Beckjord	6	(C)	52	52	-	-
Big Sandy	1-2		1,078	1,078	-	-
Cardinal	1		595	585	-	-
Ceredo (Gas)	1-6		516	450	-	-
Clinch River	1-3		705	690	-	-
Conesville	3,5-6		965	965	-	-
Conesville	4	(C)	337	337	-	-
Cook Nuclear	1-2		2,191	2,059	2,191	2,059
Darby (Gas)	1-6		507	438	-	-
Gen. J. M. Gavin	1-2		2,640	2,630	-	-
Glen Lyn	5-6		335	325	-	-
Kammer	1-3		630	400	-	-
Kanawha River	1-2		400	400	-	-
Lawrenceburg (Gas)	1-6		1,186	1,120	-	-
Mitchell	1-2		1,560	1,560	-	-
Mountaineer	1		1,320	1,305	-	-
Muskingum River	1-5		1,440	1,375	-	-
Picway	5		100	95	-	-
Rockport	1-2		2,620	2,615	2,227	2,223
Smith Mtn. (Pumped Storage)	1-5		586	586	-	-
Sporn	1-5		1,050	580	-	-
J. M. Stuart	1-4	(C)	604	604	-	-
J. M. Stuart (Diesel)	1-4	(C)	3	3	-	-
Tanners Creek	1-4		995	985	995	985
Waterford (Gas)	1-4		840	810	-	-
W. H. Zimmer	1	(C)	330	330	-	-
Conventional Hydro			133	98	15	12
Total Excl. Buckeye			26,618	25,340	5,428	5,279
Cardinal (Buckeye Power)	2-3	(D)	1,225	1,215	-	-
Total Incl. Buckeye			27,843	26,555	5,428	5,279
Capacity Purchases						
Clifty & Kyger (OVEC)	1-6	(E)	980	947	177	171
Beach Ridge (Wind)		(I)	13	13	-	-
Camp Grove (Wind)		(I)	17	20	-	-
Fowler Ridge Phase 1 & 3 (Wind)		(I)	31	36	16	17
Grand Ridge Phase 2 & 3 (Wind)		(I)	13	19	-	-
Fowler Ridge Phase 2 (Wind)		(I)	20	24	7	8
Wyandotte (Solar)		(I)	1	4	-	-
Robert Mone (Gas)	1-3	(F)	135	49	26	9
Constellation Energy (Gas)			315	315	61	61
SEPA (Hydro)			4	4	1	1
Summersville (Hydro)			28	14	-	-
Total Purchases			1,556	1,445	287	267
Total Incl. Buckeye and Purchases			29,398	27,999	5,715	5,546

NOTES:

A. Except where stated otherwise, all units are coal fired.
B. I&M plant capabilities based on AEP System Interconnection Agreement pool view.
C. Capability shown reflects CSP's share of unit owned jointly with CG&E and DP&L.
D. Cardinal Units 2 and 3 are owned by Buckeye Power, Inc.
E. AEP's and I&M's PPR shares of OVEC purchase.
F. Capability shown for I&M reflects I&M's MLR share of the Mone purchase.
G. Expected capacity at time of AEP and I&M Summer 2011 peaks.
H. Expected capacity at time of AEP and I&M Winter 2010/2011 peaks.
I. Wind and Solar capacity values are assumed to be 13% and 38% of nameplate or based on historical performance.

Exhibit 5-2

Existing I&M Generating Units (MW)

Summer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cook 1	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
Cook 2	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
Rockport 1	1,118	1,118	1,118	1,118	1,126	1,126	1,126	1,126	1,126	1,126
Rockport 2	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,135	1,135
Tanners 1	145	145	145	0	0	0	0	0	0	0
Tanners 2	145	145	145	0	0	0	0	0	0	0
Tanners 3	195	195	195	0	0	0	0	0	0	0
Tanners 4	500	500	500	500	500	500	500	500	500	500
Unit Total	5,286	5,286	5,286	4,801	4,809	4,809	4,809	4,809	4,839	4,839

Summer	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cook 1	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
Cook 2	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
Rockport 1	1,126	1,126	1,126	1,126	1,126	1,126	1,126	1,126	1,126	1,126
Rockport 2	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
Tanners 1	0	0	0	0	0	0	0	0	0	0
Tanners 2	0	0	0	0	0	0	0	0	0	0
Tanners 3	0	0	0	0	0	0	0	0	0	0
Tanners 4	500	500	500	0	0	0	0	0	0	0
Unit Total	4,839	4,839	4,839	4,339	4,339	4,339	4,339	4,339	4,339	4,339

Note: Rockport is based on I&M's portion only (85% Unit 1 & 85% of Unit 2)

Note: No unit sales are reflected here

Exhibit 5-3

I&M
PJM Capacity (UCAP) Position

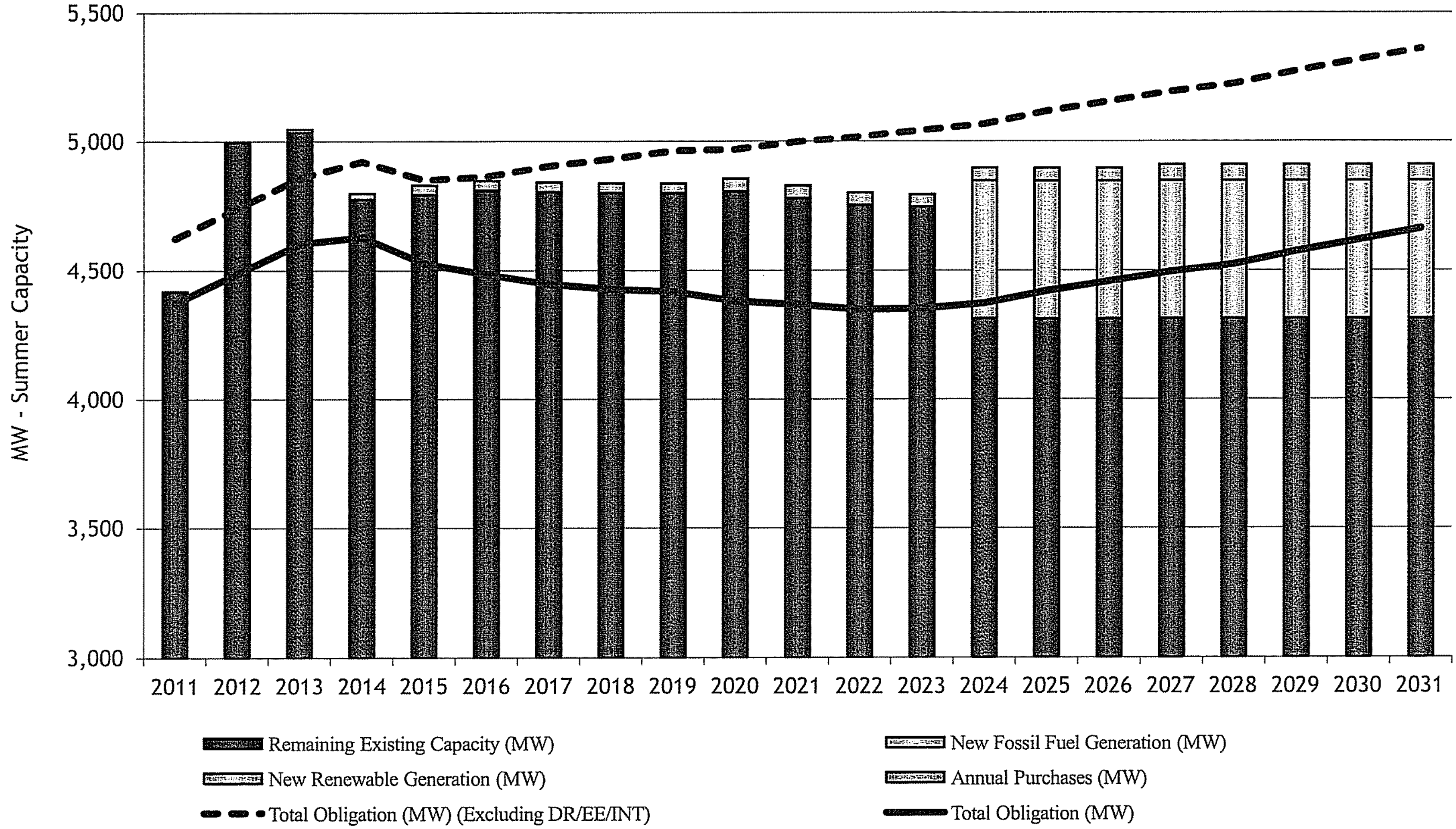
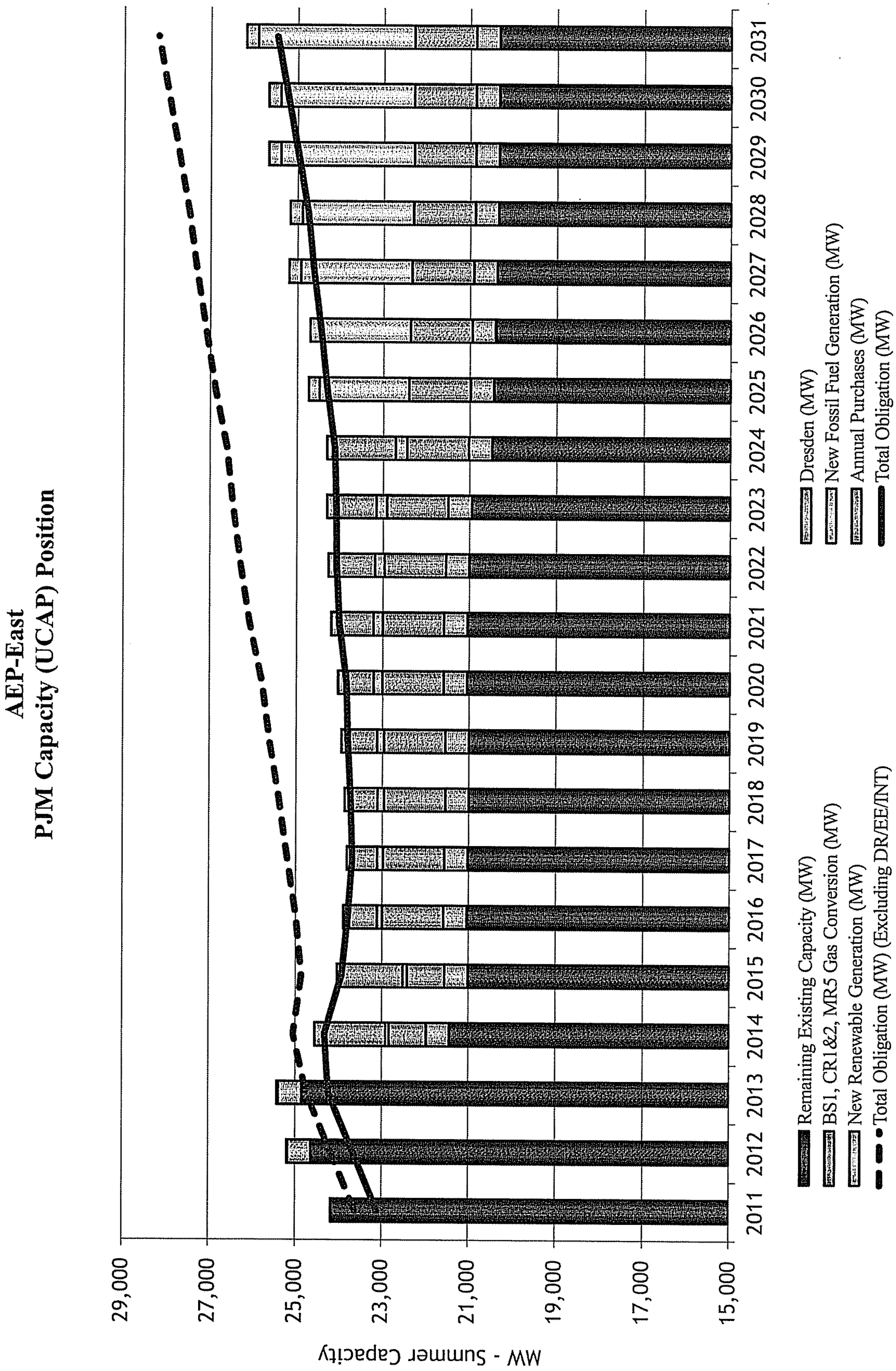
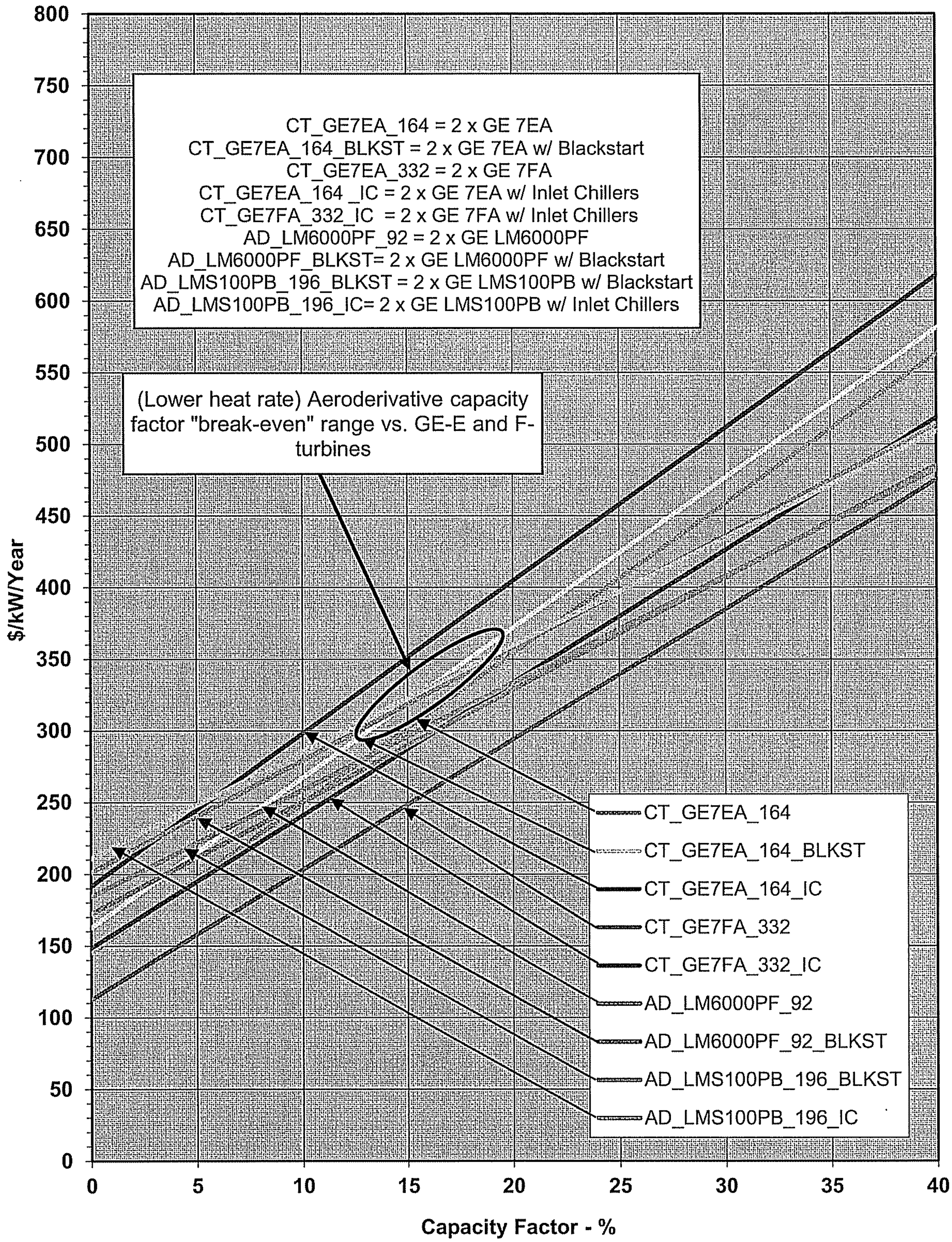


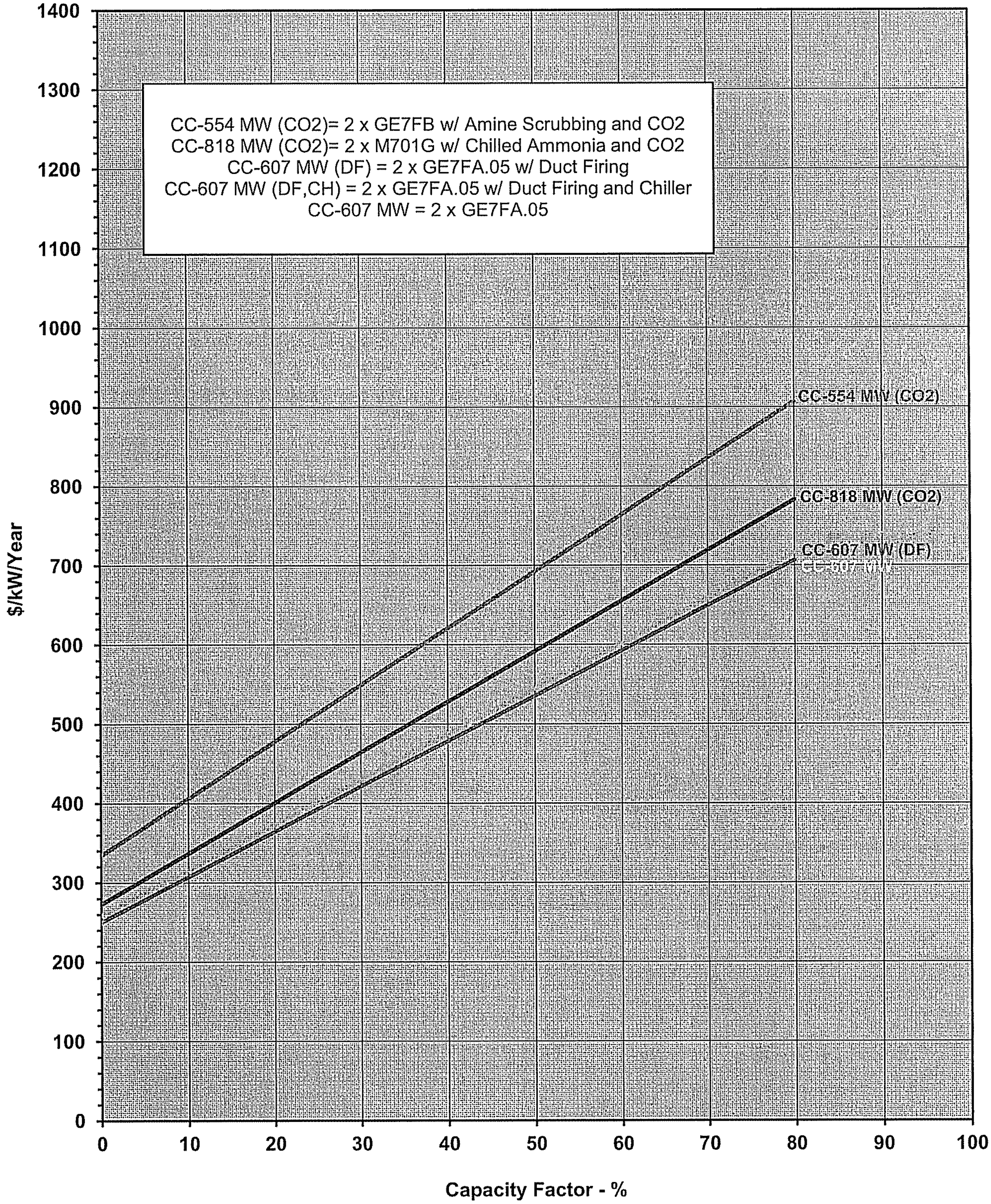
Exhibit 5-4


AEP-East
PJM Capacity (UCAP) Position
MW - Summer Capacity
29,000
27,000
25,000
23,000
21,000
19,000
17,000
15,000
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Remaining Existing Capacity (MW)
BS1, CR1&2, MR5 Gas Conversion (MW)
New Renewable Generation (MW)
Total Obligation (MW) (Excluding DR/EE/INT)
Dresden (MW)
New Fossil Fuel Generation (MW)
Annual Purchases (MW)
Total Obligation (MW)

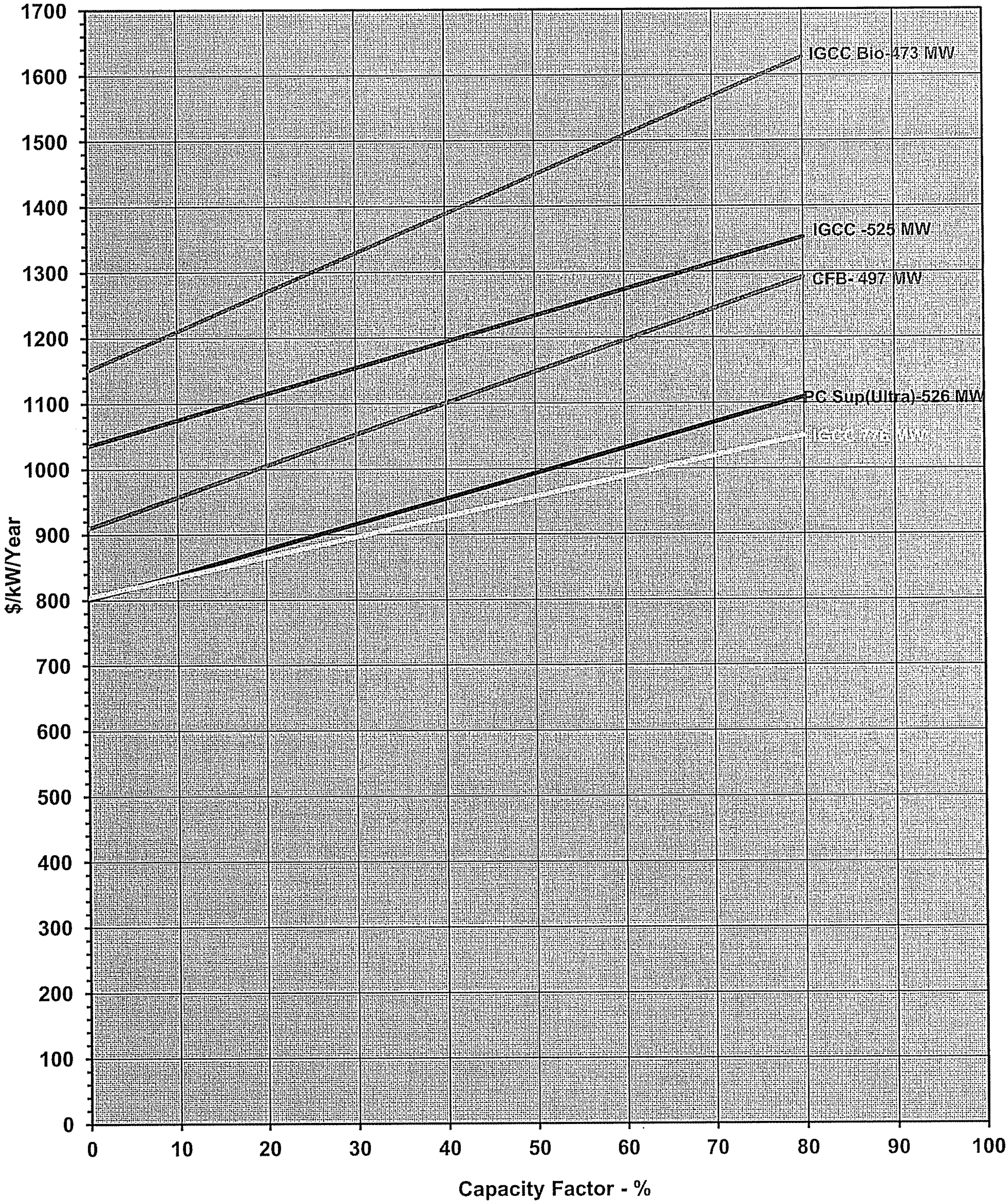
AEP System-East Zone
Peaking Capacity Options (Multiple Unit Installations)
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)



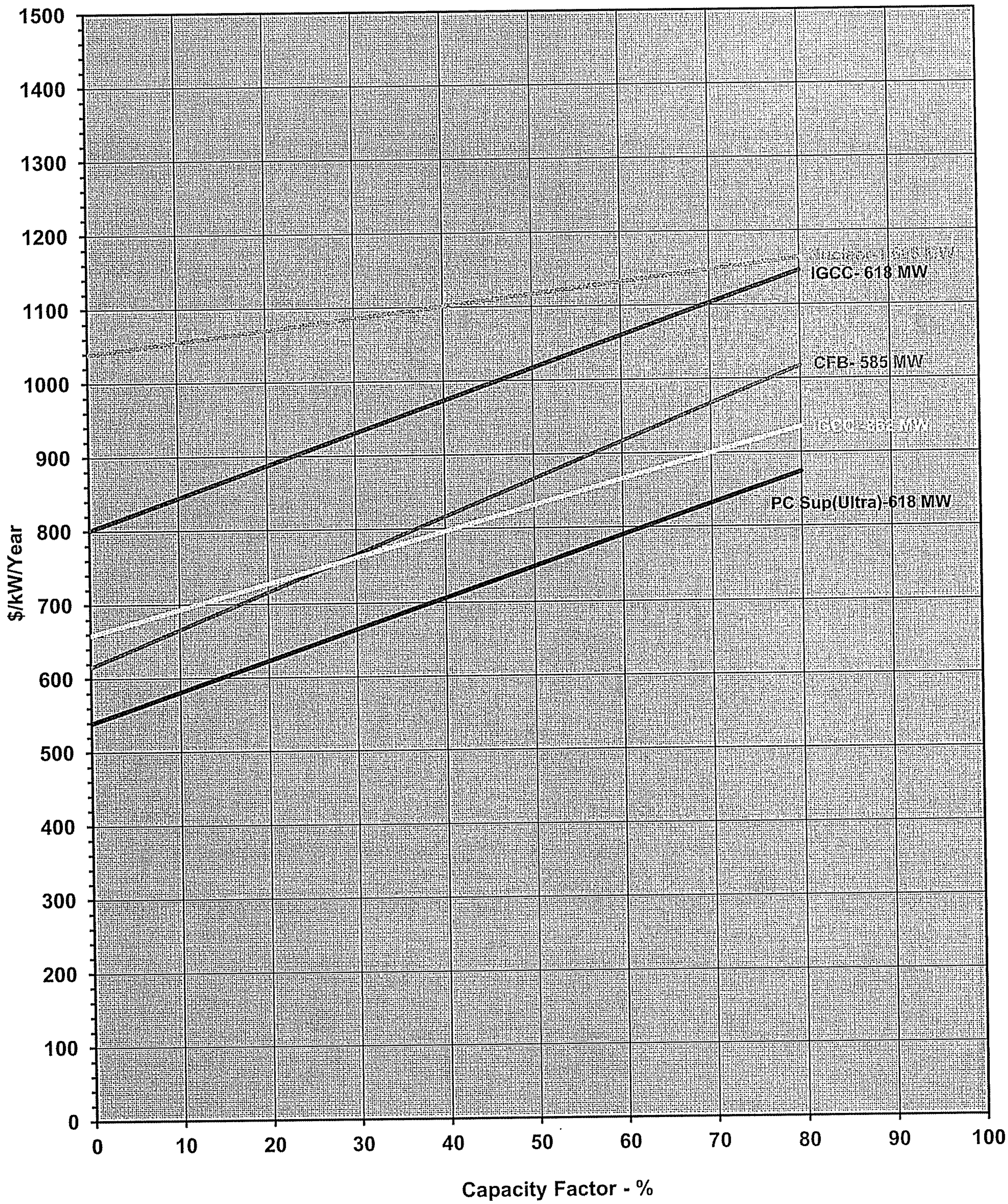
AEP System-East Zone
Intermediate Capacity Options (Inc. Duct Firing and New Option w/ 90% CO2 Capture)
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)



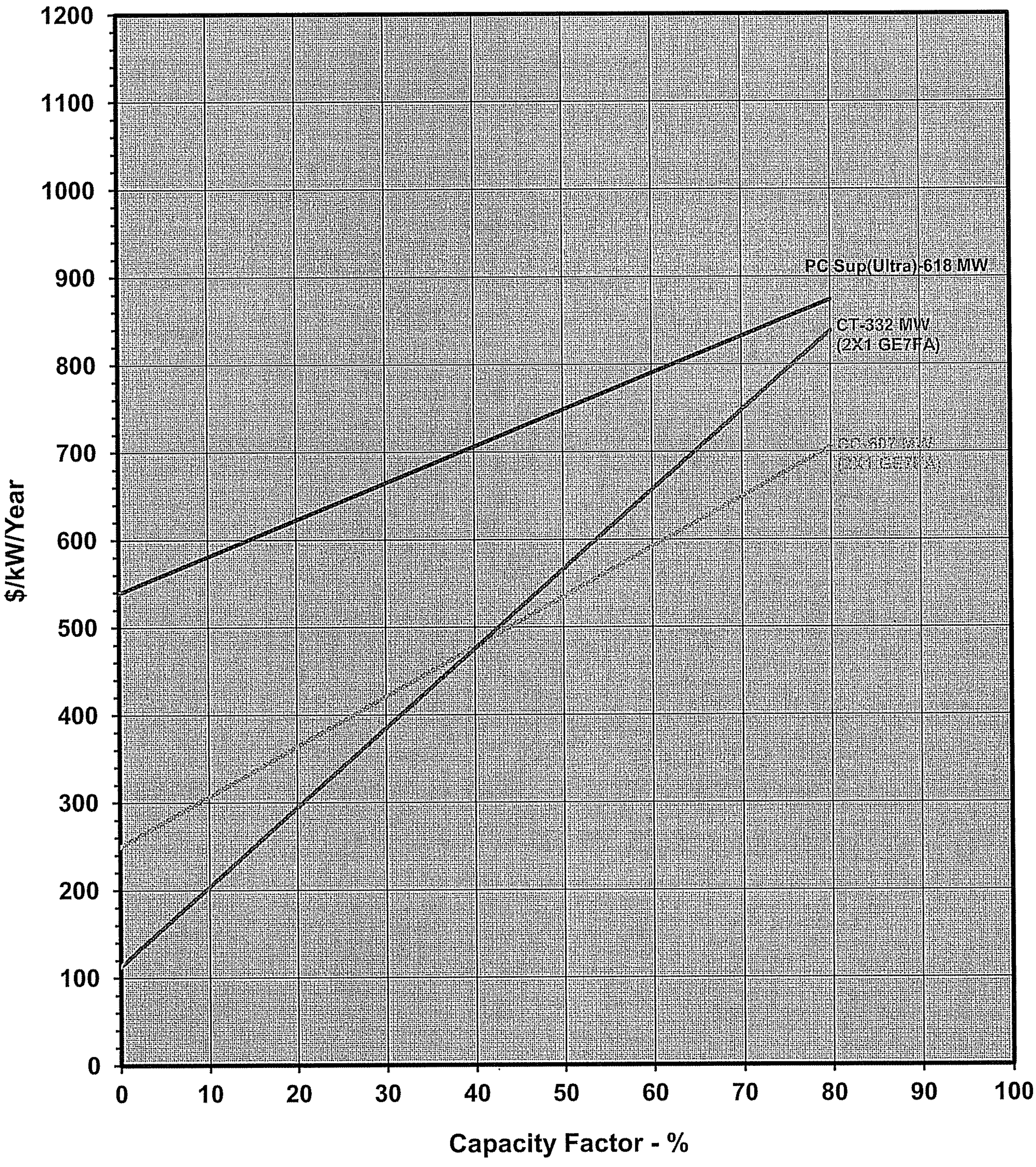
AEP System-East Zone
Base Load Capacity Options with 90% CO2 Capture
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)



AEP System-East Zone
Base Load Capacity Options
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)



AEP System-East Zone
Lowest Cost Base, Intermediate and Peaking Options (MultipleUnit)
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)



Forecasted Capacity Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MW-Day (Nominal)

AEP GEN HUB (PJM RTO)

Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$55.44	$55.44	$55.44
2013	$23.03	$23.03	$23.03
2014	$26.14	$26.14	$26.14
2015	$25.00	$25.00	$25.00
2016	$58.67	$52.56	$25.00
2017	$128.80	$126.00	$25.00
2018	$162.33	$159.61	$66.67
2019	$194.72	$192.27	$121.58
2020	$226.01	$224.01	$238.36
2021	$255.14	$253.29	$308.32
2022	$282.32	$280.43	$307.94
2023	$311.63	$306.72	$308.79
2024	$327.79	$322.74	$310.91
2025	$343.29	$345.90	$314.36
2026	$358.11	$357.93	$319.64
2027	$372.21	$368.96	$326.01
2028	$385.56	$378.93	$333.89
2029	$397.73	$387.42	$343.07
2030	$409.05	$394.76	$353.73

Exhibit 8-2

Forecasted Natural Gas Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MMBtu (Nominal)

	TCO Pool			TCO Delivered		
Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$4.29	$4.31	$3.55	$4.59	$4.61	$3.84
2013	$4.77	$4.77	$3.93	$5.08	$5.09	$4.22
2014	$5.11	$5.11	$4.20	$5.42	$5.43	$4.50
2015	$5.21	$5.21	$4.28	$5.53	$5.53	$4.58
2016	$5.42	$5.42	$4.45	$5.75	$5.75	$4.75
2017	$5.57	$5.45	$4.48	$5.90	$5.78	$4.78
2018	$6.08	$5.69	$4.67	$6.42	$6.03	$4.98
2019	$6.30	$5.90	$4.85	$6.65	$6.24	$5.16
2020	$6.46	$6.07	$4.99	$6.81	$6.42	$5.30
2021	$6.69	$6.29	$5.17	$7.05	$6.64	$5.48
2022	$6.82	$6.55	$5.37	$7.18	$6.90	$5.70
2023	$7.00	$6.74	$5.53	$7.36	$7.09	$5.86
2024	$7.23	$6.96	$5.71	$7.60	$7.32	$6.04
2025	$7.44	$7.17	$5.88	$7.81	$7.53	$6.22
2026	$7.56	$7.26	$5.96	$7.93	$7.63	$6.30
2027	$7.72	$7.43	$6.10	$8.10	$7.80	$6.43
2028	$7.88	$7.59	$6.23	$8.26	$7.96	$6.57
2029	$8.07	$7.76	$6.37	$8.45	$8.14	$6.72
2030	$8.17	$7.87	$6.46	$8.56	$8.24	$6.80

Forecasted Energy Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MWh (Nominal)

AEP GEN HUB (PJM RTO)

	Fleet Transition (FT Case)		Fleet Transition Carbon Adjusted (FTCA Case)		Low Band (L Case)	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2012	$45.47	$27.57	$46.84	$27.42	$41.52	$25.09
2013	$49.56	$30.97	$50.04	$30.73	$44.95	$28.02
2014	$53.17	$32.76	$53.56	$32.93	$48.82	$30.01
2015	$54.11	$33.57	$54.92	$33.53	$49.31	$30.22
2016	$54.18	$32.67	$55.58	$32.63	$49.59	$29.25
2017	$67.17	$48.10	$57.29	$33.79	$50.54	$29.93
2018	$69.34	$49.84	$60.51	$36.08	$52.62	$31.15
2019	$71.01	$52.41	$61.93	$37.97	$53.58	$32.91
2020	$71.76	$54.41	$63.30	$39.89	$55.16	$35.29
2021	$72.16	$55.75	$64.04	$41.29	$55.87	$36.19
2022	$73.74	$57.00	$72.78	$51.50	$65.00	$46.65
2023	$75.01	$57.29	$74.37	$52.71	$67.12	$48.08
2024	$76.72	$58.79	$75.48	$53.94	$67.91	$48.89
2025	$77.18	$60.16	$77.35	$55.55	$68.47	$49.98
2026	$78.85	$61.41	$78.47	$56.66	$68.77	$50.37
2027	$79.43	$62.51	$79.73	$57.44	$71.18	$52.24
2028	$81.36	$63.65	$81.84	$59.20	$71.75	$52.78
2029	$82.43	$65.04	$82.13	$60.20	$73.03	$54.16
2030	$83.21	$65.77	$83.85	$61.62	$73.58	$54.88

Exhibit 8-4

Forecasted Coal Prices (FOB)
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/Ton (Nominal)

	CAPP NYMEX			PRB 8800		
Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$79.00	$79.00	$68.25	$14.80	$14.80	$12.11
2013	$81.00	$81.00	$69.98	$15.55	$15.55	$12.72
2014	$79.00	$79.00	$68.25	$15.61	$15.61	$12.77
2015	$80.11	$80.11	$69.21	$15.95	$15.99	$13.08
2016	$81.22	$81.22	$70.17	$16.29	$16.37	$13.39
2017	$80.83	$82.77	$71.50	$16.60	$16.76	$13.71
2018	$80.83	$84.35	$72.87	$16.91	$17.16	$14.04
2019	$81.59	$85.94	$74.24	$17.23	$17.57	$14.38
2020	$82.34	$87.53	$75.62	$17.55	$17.99	$14.71
2021	$83.86	$89.32	$77.16	$17.88	$18.41	$15.06
2022	$85.41	$88.93	$76.82	$18.21	$18.47	$15.11
2023	$86.98	$90.73	$78.38	$18.54	$18.90	$15.46
2024	$88.56	$92.56	$79.96	$18.88	$19.34	$15.82
2025	$90.15	$94.41	$81.56	$19.22	$19.78	$16.18
2026	$91.75	$96.28	$83.18	$19.56	$20.24	$16.55
2027	$93.38	$98.18	$84.81	$19.90	$20.70	$16.93
2028	$95.02	$100.10	$86.48	$20.25	$21.16	$17.31
2029	$96.69	$102.06	$88.17	$20.61	$21.64	$17.70
2030	$98.37	$104.04	$89.88	$20.97	$22.13	$18.10

Forecasted CO_2 Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/Tonne (Nominal)

Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$0.00	$0.00	$0.00
2013	$0.00	$0.00	$0.00
2014	$0.00	$0.00	$0.00
2015	$0.00	$0.00	$0.00
2016	$0.00	$0.00	$0.00
2017	$18.74	$0.00	$0.00
2018	$19.84	$0.00	$0.00
2019	$20.94	$0.00	$0.00
2020	$22.05	$0.00	$0.00
2021	$22.33	$0.00	$0.00
2022	$22.62	$15.08	$15.08
2023	$22.92	$15.28	$15.28
2024	$23.21	$15.48	$15.48
2025	$23.51	$15.67	$15.67
2026	$23.82	$15.88	$15.88
2027	$24.13	$16.08	$16.08
2028	$24.45	$16.29	$16.29
2029	$24.77	$16.50	$16.50
2030	$25.07	$16.72	$16.72

I&M Under Various Commodity Pricing (Feb Load Forecast)
Capacity Resource Optimization
Expansion Plan Summary

	"Base" Plan	"Gas" Plan	"Market" Plan
2011-2014			
2015			201 MW - ICAP
2016			135 MW - ICAP
2017		1- 618 MW CC	103 MW - ICAP
2018			88 MW - ICAP
2019			78 MW - ICAP
2020			35 MW - ICAP
2021			50 MW - ICAP
2022			57 MW - ICAP
2023			70 MW - ICAP
2024	1- 618 MW CC		1- 618 MW CC
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035	2- 618 MW CC	2- 618 MW CC	2- 618 MW CC
2036			
2037	2- 618 MW CC	2- 618 MW CC	2- 618 MW CC
2038	1- 618 MW CC	1- 618 MW CC	1- 618 MW CC
2039			
2040			
Fleet Transition 2011-2040 CPW ($000)	**$17,198,538**	**$17,363,153**	**$17,263,653**
Fleet Transition Carbon Adjusted 2011-2040 CPW ($000)	**$16,614,321**	**$16,815,432**	**$16,713,730**
Low Band 2011-2040 CPW ($000)	**$17,238,172**	**$17,374,907**	**$17,292,470**

AEP-East Under Various Commodity Pricing (Feb Load Forecast)
Capacity Resource Optimization
Expansion Plan Summary

	Fleet Transition Pricing		Fleet Transition - Carbon Adjusted Pricing		Low Band Pricing	
	Market Plan Optimization ICAP Purchases (MW)	**Build Plan** Optimization ICAP and New Unit Additions	**Market Plan** Optimization ICAP Purchases (MW)	**Build Plan** Optimization ICAP and New Unit Additions	**Market Plan** Optimization ICAP Purchases (MW)	**Build Plan** Optimization ICAP and New Unit Additions
2011 -2013						
2014	1,776	1,776 MW ICAP	1,776	1,776 MW ICAP	1,776	1,776 MW ICAP
2015	1,643	1,563 MW ICAP	1,563	1,563 MW ICAP	1,563	1,563 MW ICAP
2016	843	843 MW ICAP	843	843 MW ICAP	843	843 MW ICAP
2017	757	2-618 MW CCs	757	1-618 MW CC, 7-86 MW CTs	757	2-618 MW CCs
2018	823		823		823	
2019	888		888		888	
2020	885		885		885	
2021	1,052		1,052		1,052	
2022	1,158	7-86 MW CTs	1,158	1-618 MW CC	1,158	1-618 MW CC
2023	1,230		1,230		1,230	
2024	1,718	1-618 MW CC	1,718	1-618 MW CC	1,718	1-618 MW CC
2025	3-618 MW CCs, 7-86 MW CTs		3-618 MW CCs, 7-86 MW CTs		4-618 MW CCs	
2026						
2027	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	1-618 MW CC	1-618 MW CC
2028						
2029	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs
2030						
2031	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	7-86 MW CTs	7-86 MW CTs
2032						
2033						
2034	7-86 MW CTs	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC
2035	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs
2036						
2037	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs
2038						
2039	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC
2040						
2011-2040 CPW ($000)	**85,209,474**	**85,445,026**	**78,636,155**	**78,881,519**	**84,701,834**	**84,923,870**

I&M Capacity Portfolio (Stand-Alone View)

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12						14	258	
2012 /13						23	258	
2013 /14			100	13		49	258	
2014 /15	(485)		100	13		123	258	0
2015 /16			100	13		186	258	0
2016 /17						249	258	0
2017 /18						313	258	0
2018 /19						353	258	0
2019 /20						389	258	0
2020 /21		30	100	13		408	258	0
2021 /22						412	258	0
2022 /23						415	258	0
2023 /24						418	258	0
2024 /25	(500)				562	419	258	0
2025 /26						423	258	0
2026 /27						423	258	0
2027 /28			100	13		423	258	0
2028 /29						422	258	0
2029 /30						423	258	0
2030 /31						423	258	0
2031 /32						423	258	0
	(985)	**30**	**500**	**65**	**562**	**423**	**258**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

AEP-East Capacity Portfolio

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12		(10)				123	519	0
2012 /13	(560)		117	20	580	199	519	0
2013 /14			120	21		302	519	0
2014 /15	(3,747)	(136)	232	38		570	519	1,776
2015 /16	(278)		215	32		823	519	1,643
2016 /17			150	20	602	1,100	519	843
2017 /18			150	20		1,365	519	757
2018 /19			117	20		1,478	519	823
2019 /20			100	13		1,617	519	888
2020 /21		35	271	40		1,765	519	885
2021 /22			100	13		1,870	519	1,052
2022 /23			100	13		1,955	519	1,158
2023 /24			200	26		2,026	519	1,230
2024 /25	(500)		21	8		2,080	519	1,718
2025 /26					2,236	2,130	519	0
2026 /27						2,142	519	0
2027 /28			100	13	550	2,142	519	0
2028 /29			50	7		2,140	519	0
2029 /30					550	2,142	519	0
2030 /31						2,142	519	0
2031 /32					562	2,142	519	0
	(5,085)	**(111)**	**2,043**	**301**	**5,080**	**2,142**	**519**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (March 2011) Load Forecast
(2011/2012 - 2031/2032)
2011 I&M IRP

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
		Obligation to PJM										Resources								I&M Position (MW)	
														Planned Capacity Additions							
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Units	MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2011 /12	(k)	4,268	(9)	0	4,268	244	0.955	1.083	4,371	0	4,371	5,502	290				5,212	15.23%	4,418	47	47
2012 /13	(k)	4,389	(17)	0	4,389	246	0.950	1.080	4,487	0	4,487	5,500	161				5,339	6.39%	4,998	511	511
2013 /14	(k)	4,496	(43)	0	4,496	246	0.957	1.080	4,603	0	4,603	5,500	116	100 MW Wind	13	0	5,397	6.47%	5,048	433	445
2014 /15	(k)	4,552	(90)	(9)	4,544	273	0.956	1.081	4,629	0	4,629	5,015	(66)	100 MW Wind	13	0	5,107	6.00%	4,801	147	172
2015 /16		4,486	(131)	(17)	4,468	295	0.956	1.081	4,526	0	4,526	5,003	(93)	100 MW Wind	13	0	5,135	5.92%	4,831	268	305
2016 /17		4,499	(166)	(43)	4,456	322	0.956	1.081	4,483	0	4,483	5,012	(102)				5,153	5.92%	4,848	328	365
2017 /18		4,536	(203)	(90)	4,446	350	0.956	1.081	4,445	0	4,445	5,012	(95)				5,146	5.92%	4,841	360	396
2018 /19		4,562	(241)	(131)	4,431	352	0.956	1.081	4,426	0	4,426	5,012	(91)				5,142	5.92%	4,838	375	412
2019 /20		4,590	(275)	(166)	4,424	354	0.956	1.081	4,416	0	4,416	5,012	(90)				5,141	5.92%	4,837	384	421
2020 /21		4,596	(291)	(203)	4,393	356	0.956	1.081	4,380	0	4,380	5,041	(68)	100 MW Wind	13	0	5,161	5.91%	4,856	427	476
2021 /22		4,624	(293)	(241)	4,383	359	0.956	1.081	4,367	0	4,367	5,041	(39)				5,132	5.91%	4,829	413	462
2022 /23		4,642	(294)	(275)	4,367	361	0.956	1.081	4,347	0	4,347	5,041	(11)				5,104	5.91%	4,802	406	455
2023 /24		4,665	(294)	(291)	4,374	364	0.956	1.081	4,352	0	4,352	5,041	(3)				5,096	5.91%	4,795	394	443
2024 /25		4,686	(293)	(293)	4,394	366	0.956	1.081	4,371	0	4,371	4,541	(2)	562 MW CC	562	0	5,157	5.04%	4,897	(57)	526
2025 /26		4,733	(294)	(294)	4,440	369	0.956	1.081	4,418	0	4,418	4,541	(1)				5,156	5.04%	4,896	(105)	478
2026 /27		4,768	(294)	(294)	4,474	369	0.956	1.081	4,456	0	4,456	4,541	(1)				5,156	5.04%	4,896	(143)	440
2027 /28		4,803	(294)	(293)	4,509	369	0.956	1.081	4,494	0	4,494	4,541	(1)	100 MW Wind	13	0	5,169	5.02%	4,910	(180)	416
2028 /29		4,831	(293)	(294)	4,537	369	0.956	1.081	4,523	0	4,523	4,541	(1)				5,169	5.02%	4,910	(209)	387
2029 /30		4,877	(294)	(294)	4,583	369	0.956	1.081	4,573	0	4,573	4,541	(1)				5,169	5.02%	4,910	(259)	337
2030 /31		4,917	(294)	(294)	4,623	369	0.956	1.081	4,617	0	4,617	4,541	(1)				5,169	5.02%	4,910	(303)	293
2031 /32		4,958	(294)	(293)	4,665	369	0.956	1.081	4,661	0	4,661	4,541	(1)				5,169	5.02%	4,910	(347)	249

Notes:
(a) Based on (March 2011) Load Forecast (with implied PJM diversity factor)
Includes company MLR share of NCEMC

(b) Existing plus approved and projected "Passive" EE, and IVV
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~3 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.5%(2010-2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
AEP share of OVEC capacity (7.95% PPR-share of full ~2,180 total capacity)
Assumes hydro units are derated to August average output in 2015/16
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2011/12: Cook 2: 14 MW (Uprate)
2015/16: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve)
FGD DERATES:
2011/12: Kyger Creek 1-5: 3 MW each
2012/13: Clifty Creek 1-6: 2 MW each
2015/16: Rockport 1: 35 MW
DSI DERATES:
2013/14: Rockport 2: 0 MW; Tanners Ck. 4 0 MW
SCR DERATES:
2015/16: Rockport 1: 0 MW
RETIREMENTS:
2014/15: Tanners Ck. 1-3
2024/25: Tanners Ck. 4

(h) Includes company MLR share of:
Constellation purchase of 315 MW in 2010/11-2011/12
Sale of 22 MW from Tanners Ck. 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA
2010/11-2012/13 (45 MW, 387 MW, 160 MW)
RPM Auction Sales 2010/11 - 2013/14 (1458, 1414, 696
, 761)(MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels
--reflected as a UCAP '<resource>'-- as part of PJM's emerging
auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30 of the previous year

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Exhibit 8-10

AEP SYSTEM - EASTERN ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (March 2011) Load Forecast
(2011/2012 - 2031/2032)
2011 I&M IRP

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
				=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
	Obligation to PJM										Resources								AEP Position (MW)	
Planning Year	Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions Units	MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2011 /12 (k)	20,515	(76)	(1)	20,514	492	0.955	1.083	21,713	1,396	23,109	28,312	1,505				26,807	9.83%	24,172	1,063	1,063
2012 /13 (k)	21,098	(149)	(1)	21,097	495	0.950	1.080	22,271	1,396	23,667	27,740	776	580 MW D CC & 17 MW Solar & 100 MW Wind	600	0	27,564	8.61%	25,191	975	1,524
2013 /14 (k)	21,610	(252)	(1)	21,609	495	0.957	1.080	22,833	1,396	24,229	27,740	567	20 MW Solar & 100 MW Wind	21	0	27,793	8.52%	25,425	629	1,196
2014 /15 (k)	21,882	(390)	(76)	21,806	625	0.956	1.081	22,924	1,396	24,320	23,857	(242)	32 MW Solar & 200 MW Wind & 1776 MW ICAP	38	1,776	26,533	7.46%	24,554	(375)	234
2015 /16	21,709	(523)	(149)	21,561	745	0.956	1.081	22,536	1,396	23,932	23,303	(315)	15 MW Solar & 200 MW Wind & 1643 MW ICAP	32	1,643	25,951	7.37%	24,038	(533)	106
2016 /17	21,827	(650)	(252)	21,576	895	0.956	1.081	22,397	1,396	23,793	23,313	(335)	602 MW BS1RP & 150 MW Wind & 843 MW ICAP	622	843	25,803	7.38%	23,899	(1,109)	106
2017 /18	22,013	(765)	(390)	21,623	1,045	0.956	1.081	22,293	1,396	23,689	23,313	(316)	150 MW Wind & 757 MW ICAP	20	757	25,717	7.37%	23,822	(1,100)	133
2018 /19	22,194	(866)	(523)	21,672	1,057	0.956	1.081	22,333	1,396	23,729	23,313	(289)	17 MW Solar & 100 MW Wind & 823 MW ICAP	20	823	25,776	7.37%	23,876	(1,104)	147
2019 /20	22,396	(993)	(650)	21,746	1,070	0.956	1.081	22,400	1,396	23,796	23,313	(290)	100 MW Wind & 888 MW ICAP	13	888	25,855	7.36%	23,952	(1,108)	156
2020 /21	22,560	(1,128)	(765)	21,795	1,082	0.956	1.081	22,440	1,396	23,836	23,348	(303)	21 MW Solar & 250 MW Wind & 885 MW ICAP	40	885	25,940	7.35%	24,033	(1,103)	197
2021 /22	22,823	(1,221)	(866)	21,957	1,095	0.956	1.081	22,603	1,396	23,999	23,348	(298)	100 MW Wind & 1052 MW ICAP	13	1,052	26,115	7.35%	24,196	(1,116)	197
2022 /23	23,022	(1,293)	(993)	22,029	1,108	0.956	1.081	22,668	1,396	24,064	23,348	(253)	100 MW Wind & 1158 MW ICAP	13	1,158	26,189	7.34%	24,267	(1,122)	203
2023 /24	23,186	(1,350)	(1,128)	22,058	1,121	0.956	1.081	22,685	1,396	24,081	23,348	(193)	200 MW Wind & 1230 MW ICAP	26	1,230	26,227	7.34%	24,302	(1,128)	221
2024 /25	23,324	(1,391)	(1,221)	22,104	1,134	0.956	1.081	22,720	1,396	24,116	22,848	(149)	21 MW Solar & 1718 MW ICAP	8	1,718	26,179	7.15%	24,307	(1,168)	191
2025 /26	23,573	(1,427)	(1,293)	22,280	1,148	0.956	1.081	22,896	1,396	24,292	22,848	(119)	1686 MW CC & 550 MW CT	2,236	0	26,666	7.20%	24,746	(2,979)	454
2026 /27	23,763	(1,439)	(1,350)	22,413	1,148	0.956	1.081	23,041	1,396	24,437	22,848	(80)				26,627	7.20%	24,710	(3,160)	273
2027 /28	23,963	(1,439)	(1,391)	22,572	1,148	0.956	1.081	23,213	1,396	24,609	22,848	(45)	550 MW CT & 100 MW Wind	563	0	27,155	7.21%	25,197	(3,367)	588
2028 /29	24,129	(1,437)	(1,427)	22,702	1,148	0.956	1.081	23,352	1,396	24,748	22,848	(13)	50 MW Wind	7	0	27,129	7.21%	25,173	(3,535)	425
2029 /30	24,354	(1,439)	(1,439)	22,915	1,148	0.956	1.081	23,583	1,396	24,979	22,848	(4)	550 MW CT	550	0	27,670	7.23%	25,669	(3,779)	690
2030 /31	24,573	(1,439)	(1,439)	23,134	1,148	0.956	1.081	23,819	1,396	25,215	22,848	(4)				27,670	7.23%	25,669	(4,015)	454
2031 /32	24,798	(1,439)	(1,437)	23,361	1,148	0.956	1.081	24,066	1,396	25,462	22,848	(4)	562 MW CC	562	0	28,232	7.24%	26,188	(4,264)	726

Notes:

(a) Based on (March 2011) Load Forecast (with implied PJM diversity factor)
Includes Monongahela Power & NCEMC

(b) Existing plus approved and projected "Passive" EE, and IVV
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~3 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.5%(2010-2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes:
FRR view of obligations only
Buckeye Cardinal and Mone obligations

(g) Reflects the following summer capability assumptions:
AEP share of OVEC capacity (7.95% PPR-share of full ~2,180 total capacity)
Assumes hydro units, including Summersville, are derated to August average output in 2015/16
Wind Farm PPAs
EFFICIENCY IMPROVEMENTS:
2010/11: Amos 1: 12 MW (turbine)
2011/12: Cook 2: 14 MW (Uprate); Gavin 2: 0 MW (turbine)
2015/16: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve)

(g) continued
CCS DERATES:
2011/12: Mountaineer 1: -6 MW (CCS Program Terminated)
FGD DERATES:
2010/11: Amos 1: 22 MW
2011/12: Cardinal 3: 10 MW; Kyger Creek 1-5: 3 MW each
2012/13: Clifty Creek 1-6: 2 MW each
2015/16: Rockport 1: 35 MW
DSI DERATES:
2013/14: Rockport 2: 0 MW; Tanners Ck. 4 0 MW
2015/16: Conesville 5: 0 MW; Conesville 6: 0 MW
SCR DERATES:
2015/16: Conesville 5: 4 MW; Conesville 6: 4 MW; Rockport 1: 0 MW
GAS CONVERSION DERATES:
2014/15: Clinch R. 1-2: 10% each; Muskingum River 5: 15%
RETIREMENTS:
2010/11: Sporn 5
2012/13: Conesville 3; Muskingum River 2,4
2014/15: Beckjord 6; Big Sandy 2; Clinch R. 3; Glen Lyn 5-6
2014/15: Kammer 1-3; Kanawha R. 1-2; Muskingum River 1,3
2014/15: Picway 5; Sporn 1-4; Tanners Ck. 1-3
2015/16: Big Sandy 1
2024/25: Tanners Ck. 4

(h) Includes:
Constellation purchase of 315 MW in 2010/11-2011/12
Sale of 22 MW from Tanners Ck. 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA
2010/11-2012/13 (45 MW, 387 MW, 160 MW)
RPM Auction Sales 2010/11 - 2013/14 (1458, 1414, 696, 761)(MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels --reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Exhibit 8-11

INDIANA MICHIGAN POWER COMPANY
INTEGRATED RESOURCE PLAN
FINANCIAL INFORMATION
($ Millions)

Year	Nominal Value of Revenue Requirements	Discount Rate	Present Value of Revenue Requirements	Real Value of Revenue Requirements	Average Rate (Cents/kWh)
2011	1310	11.80%	1310	1310	5.61
2012	1417	11.80%	1267	1390	5.79
2013	1523	11.80%	1218	1466	5.51
2014	1533	11.80%	1097	1449	5.47
2015	1579	11.80%	1011	1464	5.55
2016	1750	11.80%	1002	1591	6.06
2017	1781	11.80%	912	1590	6.08
2018	1818	11.80%	833	1592	6.12
2019	1841	11.80%	754	1582	6.10
2020	1901	11.80%	697	1603	6.19
2021	1949	11.80%	639	1612	6.21

Notes:

(1) Present values are calculated using a mid-year convention along with I&M's discount rate (shown above).

(2) Real dollar values are calculated using an inflation rate of 1.91%. This rate is estimated to be an average for all customers.

(3) Discount Rate based on incremental pretax weighted average cost of capital per Finance Dept.

(4) Average rate calculated by dividing Real Value of Revenue Requirements by Internal GWh Sales.

(5) Data is only available through 2021.

Forecasted Capacity Prices
2011-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MW-Day (Nominal)

AEP GEN HUB (PJM RTO)

Year	Fleet Transition Carbon Adjusted (FTCA Case)
2012	$55.44
2013	$23.03
2014	$26.14
2015	$25.00
2016	$52.56
2017	$126.00
2018	$159.61
2019	$192.27
2020	$224.01
2021	$253.29
2022	$280.43
2023	$306.72
2024	$322.74
2025	$345.90
2026	$357.93
2027	$368.96
2028	$378.93
2029	$387.42
2030	$394.76

I&M
ESTIMATED "AVOIDED COSTS" OF ENERGY
FOR ASSUMED LEVELS OF COGENERATION PURCHASES
2012 - 2021
(Cents Per Kilowatt-Hour)

ASSUMED COGENERATION PURCHASE LEVEL
100-MW Block

	Peak	Off-Peak
2012	3.42	2.92
2013	3.29	2.91
2014	4.40	3.71
2015	4.46	3.46
2016	3.94	3.15
2017	3.85	3.10
2018	4.00	3.21
2019	4.16	3.35
2020	4.23	3.43
2021	4.34	3.53

Notes:
A. Seasonal differences in energy costs are not sufficiently significant and/or consistent to warrant establishment of separate seasonal costing periods
B. The peak costing period is 0700 to 2100 local time Monday through Friday. All other hours comprise the off-peak costing period.
C. Energy costs are expressed in current-year dollars.

12) APPENDIX

Indiana Michigan Power Company

Model Equations

Results of Statistical Tests and Input Data Sets

Pertaining to the 2011 Load Forecast

(PROVIDED ON CD)

INDIANA MICHIGAN POWER COMPANY

HOURLY INTERNAL LOADS

2010

(PROVIDED ON CD)

AEP SYSTEM / INDIANA MICHIAN POWER COMPANY

HOURLY FIRM-LOAD LAMDAS

2010

(Note: No longer available due to I&M's participation in PJM. AEP joined PJM effective 10-1-04)

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW) *	Summer Rating (MW) *	Environmental Controls	Notes
Cook Nuclear	1	Bridgman	MI	1975	ST	Nuclear	#N/A	100%	1,084	1,007	CL	As of 6-1-2011
Cook Nuclear	2	Bridgman	MI	1978	ST	Nuclear	#N/A	100%	1,121	1,071	CL	As of 6-1-2011
Rockport	1	Rockport	IN	1984	ST	Coal	#N/A	85%	1,122	1,118	EP, LNB, OFA	As of 6-1-2011
Rockport	2	Rockport	IN	1989	ST	Coal	#N/A	85%	1,105	1,105	EP, LNB, OFA	As of 6-1-2011
Tanners Creek	1	Lawrenceburg	IN	1951	ST	Coal	#N/A	100%	145	145	EP, LNB	As of 6-1-2011
Tanners Creek	2	Lawrenceburg	IN	1952	ST	Coal	#N/A	100%	145	145	EP, LNB	As of 6-1-2011
Tanners Creek	3	Lawrenceburg	IN	1954	ST	Coal	#N/A	100%	205	195	EP, LNB	As of 6-1-2011
Tanners Creek	4	Lawrenceburg	IN	1964	ST	Coal	#N/A	100%	500	500	EP, OFA	As of 6-1-2011
Berrien Springs	1-12	Berrien Springs	MI	1908	HY	Water	#N/A	100%	5.2	3.1	#N/A	As of 6-1-2011
Buchanan	1-10	Buchanan	MI	1919	HY	Water	#N/A	100%	2.4	2.3	#N/A	As of 6-1-2011
Constantine	1-4	Constantine	MI	1921	HY	Water	#N/A	100%	0.8	0.5	#N/A	As of 6-1-2011
Elkhart	1-3	Elkhart	IN	1913	HY	Water	#N/A	100%	2.1	1.6	#N/A	As of 6-1-2011
Mottville	1-4	White Pigeon	MI	1923	HY	Water	#N/A	100%	0.9	0.6	#N/A	As of 6-1-2011
Twin Branch	1-8	Mishawaka	IN	1904	HY	Water	#N/A	100%	3.6	2.9	#N/A	As of 6-1-2011

* Denotes Expected Seasonal Generation Capability

Indiana Michigan Power Company

Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor

2001-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2001	08/08/01	4,232	---	12/31/00	3,393	---	4,232	---	22,284	---	60.1
2002	07/22/02	4,303	1.7	03/04/02	3,258	-4.0	4,303	1.7	23,293	4.5	61.8
2003	08/21/03	4,223	-1.9	01/07/03	3,683	13.0	4,223	-1.9	22,876	-1.8	61.8
2004	07/22/04	4,016	-4.9	01/22/04	3,465	-5.9	4,016	-4.9	22,962	0.4	65.1
2005	08/09/05	4,193	4.4	01/28/05	3,465	0.0	4,193	4.4	23,407	1.9	63.7
2006	07/31/06	4,650	10.9	12/08/05	3,537	2.1	4,650	10.9	24,419	4.3	59.9
2007	08/07/07	4,528	-2.6	02/06/07	3,945	11.5	4,528	-2.6	26,013	6.5	65.6
2008	07/31/08	4,264	-5.8	01/25/08	3,875	-1.8	4,264	-5.8	25,448	-2.2	67.9
2009	06/25/09	4,262	0.0	01/15/09	3,728	-3.8	4,262	0.0	24,296	-4.5	65.1
2010	07/23/10	4,474	5.0	12/10/09	3,858	3.5	4,474	5.0	25,828	6.3	65.9
2011*	07/21/11	4,837	8.1	12/13/10	3,785	-1.9	4,837	8.1	25,512	-1.2	60.0
Forecast											
2012		4,527	-6.4		3,932	3.9	4,527	-6.4	26,169	2.6	66.0
2013		4,613	1.9		4,007	1.9	4,613	1.9	26,621	1.7	65.9
2014		4,597	-0.4		3,988	-0.5	4,597	-0.4	26,500	-0.5	65.8
2015		4,579	-0.4		3,963	-0.6	4,579	-0.4	26,366	-0.5	65.7
2016		4,558	-0.5		3,930	-0.8	4,558	-0.5	26,244	-0.5	65.7
2017		4,560	0.0		3,915	-0.4	4,560	0.0	26,158	-0.3	65.5
2018		4,550	-0.2		3,894	-0.5	4,550	-0.2	26,039	-0.5	65.3
2019		4,545	-0.1		3,878	-0.4	4,545	-0.1	25,956	-0.3	65.2
2020		4,536	-0.2		3,856	-0.6	4,536	-0.2	25,907	-0.2	65.2
2021		4,563	0.6		3,874	0.5	4,563	0.6	25,978	0.3	65.0
2022		4,580	0.4		3,882	0.2	4,580	0.4	26,044	0.3	64.9
2023		4,605	0.5		3,888	0.2	4,605	0.5	26,152	0.4	64.8
2024		4,628	0.5		3,898	0.3	4,628	0.5	26,308	0.6	64.9
2025		4,676	1.0		3,935	0.9	4,676	1.0	26,484	0.7	64.7
2026		4,713	0.8		3,959	0.6	4,713	0.8	26,659	0.7	64.6
2027		4,750	0.8		3,983	0.6	4,750	0.8	26,834	0.7	64.5
2028		4,780	0.6		4,000	0.4	4,780	0.6	27,023	0.7	64.5
2029		4,828	1.0		4,029	0.7	4,828	1.0	27,215	0.7	64.4
2030		4,870	0.9		4,057	0.7	4,870	0.9	27,416	0.7	64.3
2031		4,912	0.9		4,088	0.8	4,912	0.9	27,622	0.8	64.2

*Total energy requirements reflect 6 months actual and 6 months forecast data. The summer peak reflects actual peak through August.

	Supply						Demand							Notes	
Year	Owned Generating Capacity (MW)	Incremental Capacity Additions (MW)	Incremental Capacity Reductions / Derates (MW)	Total Multi-Year Purchases (MW)	Annual Purchases (MW)	Total Supply Resources (MW)	Peak Internal Demand (MW)	Total Sales (MW)	Total Conservation (MW)	Total Demand Response (MW)	Net Peak Demand (MW)	Reserve Margin (%)	Capacity Additions	Capacity Reductions
2012	5,493		(3)	11	0	5,501	4,544	175	(258)	(23)	4,438	24.0%		Kyger Creek 1-5 FGD
2013	5,490	13	(2)	11	0	5,512	4,656	151	(258)	(49)	4,500	22.5%	100 MW Wind	Clifty Creek 1-6 FGD
2014	5,501	13		13	0	5,527	4,687	0	(258)	(123)	4,306	28.4%	100 MW Wind	
2015	5,514	13	(485)	13	0	5,055	4,710	0	(258)	(186)	4,266	18.5%	100 MW Wind	Tanners Creek 1-3 Retirement
2016	5,042	38	(30)	12	0	5,063	4,724	0	(258)	(249)	4,217	20.1%	Rockport 1 Valve Uprate & Seasonal Derate Removal	Rockport 1 FGD
2017	5,051			12	0	5,063	4,763	0	(258)	(313)	4,192	20.8%		
2018	5,051			12	0	5,063	4,791	0	(258)	(353)	4,180	21.1%		
2019	5,051			12	0	5,063	4,820	0	(258)	(389)	4,173	21.3%		
2020	5,051	43		12	0	5,105	4,827	0	(258)	(408)	4,161	22.7%	100 MW Wind & Rockport 2 Valve Uprate	
2021	5,093			12	0	5,105	4,856	0	(258)	(412)	4,186	22.0%		
2022	5,093			12	0	5,105	4,874	0	(258)	(415)	4,201	21.5%		
2023	5,093			12	0	5,105	4,899	0	(258)	(418)	4,223	20.9%		
2024	5,093	562		13	0	5,668	4,921	0	(258)	(419)	4,244	33.6%	562 MW CC	
2025	5,655		(500)	13	0	5,168	4,970	0	(258)	(423)	4,289	20.5%		Tanners Creek 4 Retirement
2026	5,155			13	0	5,168	5,007	0	(258)	(423)	4,326	19.5%		
2027	5,155	13		13	0	5,181	5,044	0	(258)	(423)	4,363	18.8%	100 MW Wind	
2028	5,168			13	0	5,181	5,073	0	(258)	(422)	4,393	17.9%		
2029	5,168			12	0	5,180	5,122	0	(258)	(423)	4,441	16.6%		
2030	5,168			12	0	5,180	5,164	0	(258)	(423)	4,483	15.6%		
2031	5,168			12	0	5,180	5,206	0	(258)	(423)	4,525	14.5%		
Total		695	(1,020)											

* 13% capacity factor assumed for wind (100 MW Windfarm equates to 13MW RTC)
** I&M owns 18.06% of OVEC capacity as well as all uprates and derates
*** I&M owns 85% percent of RKP1 and RKP2 as well as all uprates and derates
**** This sheet reflects a "Traditional" Summer View

Indiana Michigan Power Company

Load Research Class Interval Usage Estimation Methodology

Load Research Class Interval Usage Estimation Methodology

AEP is a participating member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee, was a significant contributor to the AEIC Load Research Manual, and uses the procedures set forth in that manual as a guide for load research practices. AEP maintains an on-going load research program in each retail rate jurisdiction which enables class hourly usage estimates to be derived from actually metered period data for each rate class for each hour of each day. The use of actual period metered data results in the effective capture of weather events and economic factors in the representation of historical usage.

For each rate class in which customer maximum demand is normally less than 1 MW, a statistical random sample is designed and selected to provide at least 10% precision at the 90% confidence level at times of company monthly peak demand. In the sample design process, billing usage for each customer in the class is utilized in conjunction with any available class interval data to determine the optimal stratified sample design using the Dalenius-Hodges stratification procedure. Neyman Allocation is used to determine the necessary number of sample customers in each stratum. All active customers with the requisite data available in the rate class population are included in the sample selection process, which uses a random systematic process to select primary sample points and backup sample points for each primary point.

For selected sample sites that reside within an AMI area, the interval data is extracted from the Meter Data Management System and imported into the ITRON MV90 System. For selected sample sites that reside outside of an AMI area, each location undergoes field review and subsequent installation of an interval data recorder. The recorder is normally set to record usage in fifteen minute intervals. For rate classes in which customer maximum demand is normally 1 MW or greater, each customer in the class is interval metered, and these are referred to as 100% sampled classes. The interval data is retrieved at least monthly, validated through use of the ITRON MV90 System, edited or estimated as necessary, and stored for analytical purposes. The status of each sample point undergoes on-going review and backup sample points replace primary sample points as facilities close, change significant parameters such as rate class, or become unable to provide required information due to safety considerations. This on-going sample maintenance process ensures reasonable sample results are continuously available, and samples are periodically refreshed through a completely new sample design and selection process to capture new building stock and when necessary to capture rate class structure changes.

Prior to analysis, as an additional verification that all interval data is correct, interval data for each customer is summed on a billing month basis and the resulting total energy and maximum demand are compared to billing quantities. Any significant discrepancies between the interval data and the billing quantities are further investigated and corrected, as needed. Rate class analysis is then performed through the MV90 Load Research Package. This industry accepted program combines the individual customer hourly data for each sample point in each stratum, weights the stratum results according to the original sample design parameters, and combines the weighted stratum results into class level results. The analysis provides hourly load estimates at both the stratum and class levels, and standard summary statistics, including non-coincident peaks, coincident peaks, coincidence factors, and load factors, at the class, stratum, and sample point levels.

The resulting class hourly load estimates are examined through various graphical approaches, the summary statistics are reviewed for consistency across time, and the monthly sample class energy results are compared against billed and booked billed and accrued values. Any anomalies are investigated, and a rate class analysis may be re-worked if the investigation shows that is necessary. When analysis and review of all rate classes is completed, losses are applied to the hourly rate class estimates, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the customer level load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary.

Rate classes are often comprised of combinations of commercial and industrial customers. Separate commercial and industrial hourly load estimates are developed after rate class analysis is completed. Monthly billing usage for each commercial and industrial customer is acquired from the customer information system and is imported into the Kema Load Research Analysis System, along with the sample point interval data available from the rate class random and 100% samples. The sample interval data is post-stratified and weighted to represent the commercial and industrial class populations, and total class hourly load estimates are developed. Losses are then applied to the resulting commercial and industrial class estimates, the values are combined with the residential class hourly load estimates from the rate class analysis, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary. Final residential, commercial, and industrial class hourly load estimates are provided to the forecasting organization for use in the long-term forecasting and planning process.

EXHIBIT ____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

**DIRECT TESTIMONY OF
ROBERT P. POWERS
IN SUPPORT OF AEP OHIO'S
MODIFIED ELECTRIC SECURITY PLAN**

Filed: March 30, 2012

SC EXHIBIT 17

INDEX TO DIRECT TESTIMONY OF
ROBERT P. POWERS

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
ROBERT P. POWERS
ON BEHALF OF
OHIO POWER COMPANY

PERSONAL DATA

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Robert P. Powers and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the American Electric Power Service Corporation (AEPSC), a unit of American Electric Power (AEP). My title is Executive Vice President and Chief Operating Officer of AEP which includes AEP Ohio, an operating unit of AEP. AEP Ohio was comprised of both Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) until December 30, 2011 at which time CSP was approved to merge into OPCo. Thus, the testimony hereby refers to OPCo as AEP Ohio or the Company.

Q. WHAT ARE YOUR RESPONSIBILITIES AS EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER OF AEP UTILITIES?

A. I am directly responsible for the overall operations of Commercial Operations, Customer and Distribution Services, Generation, Nuclear Generation, Fuel and Environmental Logistics, Regulatory Services, and AEP Utilities, which includes both West and East Utilities, including AEP Ohio. As a part of my responsibilities, I oversee and lead AEP in establishing goals that are designed to benefit customers and shareholders.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a bachelor's degree in biology from Tufts University in Boston and a master's degree in radiological hygiene (health physics) from the University of North Carolina. I earned national certification by the American Board of Health Physics and earned my senior reactor operator certification in 1991. Additionally, I completed the executive management programs run by the University of California – Berkeley and Duke University.

I joined the utility industry in 1976 when I was hired by the Tennessee Valley Authority in the nuclear program, focusing on radiation measurement and environmental assessment of the utility's nuclear power plants and uranium mining properties. In 1982, I joined Pacific Gas & Electric Company's Diablo Canyon Nuclear Generating Station as a health physicist. I was employed by PG&E for 17 years and held various positions until becoming vice president. In 1998, I joined AEP as Senior Vice President-Nuclear Generation. I was then promoted to Executive Vice-President-Nuclear and Technical Services and subsequently Executive Vice President of Generation which expanded my responsibilities to include, not only nuclear operations, but fossil-fuels as well. In 2006, I assumed the position of Executive Vice-President of AEP East Utilities, responsible for AEP's utility operating units that serve approximately 3.2 million customers in the states of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia. In 2010, I assumed the position of President of AEP Utilities which included responsibilities for all utility and regulatory assets of AEP operations. I have served in my current role as Executive Vice President and Chief Operating Officer of AEP since November 2011.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE A REGULATORY AGENCY?

A. Yes. I have testified before the U.S. Nuclear Regulatory Commission in licensing hearings, and in proceedings conducted by the State of South Dakota on the environmental impact of utility operations.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Public Utilities Commission of Ohio (Commission) AEP Ohio's Standard Service Offer (SSO) in the modified ESP cases currently pending which are Case No. 11-346-EL-SSO for CSP and Case No. 11-348-EL-SSO for OPCo (ESP II). Further, I will provide an overview of the Company's modified ESP II plan, in accordance with the Commission's order on February 23, 2012, which covers the period from June 1, 2012 through May 31, 2015. I will introduce the witnesses in the modified ESP II filing, AEP Ohio's commitment to a reasonable transition to a competitive market, the value that a competitive market involving a reasonable transition can provide to both our customers and investors, and the unique risks within the State of Ohio's electricity environment. While AEP Ohio is presenting a compromise solution in the modified ESP II that includes discounted capacity as well as a transition to market, AEP Ohio's litigation position in the capacity charge proceeding (Case No. 10-2929-EL-UNC) remains intact. In other words, the Company seeks a wholesale cost-based capacity rate and reserves the right to pursue any available legal remedies or avenues of relief before any administrative agency or federal or state court, unless the Commission issues final orders approving both the modified ESP II as presented and the corporate separation application as filed. Similarly, AEP Ohio would not be willing to provide discounted capacity and transition as quickly to market as proposed in the modified ESP if it does not receive all the benefits of the balanced package of terms in the proposed ESP, including a mechanism to help ensure AEP Ohio's financial stability during the transition.

Q. ARE YOU SPONSORING ANY EXHIBITS AS A PART OF YOUR TESTIMONY?

A. Yes, I am sponsoring Exhibit RPP-1.

<u>WITNESSES IN THE CASE AND SPONSORED TESTIMONY</u>

Q. HOW IS THE MODIFIED ESP II FILING ORGANIZED?

A. AEP Ohio has 12 witnesses supporting various key issues for the modified filing. The following table – Table 1: Witnesses in the Modified ESP II summarizes and serves to introduce the witnesses, the general ESP subject area they are sponsoring, and a brief description of their testimony.

Table 1: Witnesses in the Modified ESP II

Witness	General Subject Area	General Description of Testimony
Robert Powers	Overview of the ESP	• Overview of the modified ESP • Capacity price overview • Retail Stability Rider • Auction process overview • Corporate separation overview • Integrated package of terms and conditions
Selwyn Dias	General Policy Witness	• Advancement of state policies • Components of the modified ESP riders • Alternative Energy Standards Phase In Recovery Rider
Philip Nelson	Capacity Plan Corporate Separation Fuel Adjustment Clause (FAC) Generation resource rider (GRR) Alternative energy rider (AER) Pool termination & modification	• FRR/Capacity obligation • Transfer of AEP Ohio generation assets • Cost Recovery Mechanisms for fuel, renewable energy credits, new capacity, and pool termination

Witness	General Subject Area	General Description of Testimony
David Roush	Tariffs and Rate Design Customer Rate Impacts	• Modifications to the tariffs, terms and conditions of service • Design of the proposed rates and riders • Implementation and bill impacts
William Allen	Capacity Pricing Distribution Investment Rider (DIR) Retail Stability Rider (RSR) Detailed Implementation Plan (DIP)	• Two tiered capacity pricing • Description of how the DIR will function and the DIR revenue requirement • Need for and basis for the RSR • Customer switching levels
Laura Thomas	Aggregate Market Rate Offer (MRO) Test	• Aggregate MRO test • Competitive benchmark price development
Renee Hawkins	AEP Ohio's Capital Structure Securitization of Deferred Fuel Updated credit agency reports	• Capitalization, weighted average cost of capital (WACC), and carrying costs • Rationale and benefits of securitization of Deferred Fuel • Recent credit agency reports indicate the negative impact of the revoked ESP on the Company's credit
Oliver Sever	Pro-forma financial statements	• Forecast methodology • Forecast assumptions and results
Thomas Mitchell	Regulatory accounting	• Regulatory accounting details for proposed riders • Regulatory accounting for future recovery of deferrals
Thomas Kirkpatrick	Distribution Investment Rider (DIR) Enhanced Service Reliability Rider (ESRR) Storm Damage Recovery Mechanism gridSMART®	• Overview and description of the Distribution investment rider, which includes investment in Distribution programs • Vegetation program, gridSMART® program, and storm damage
Jay Godfrey	Request prudency for cost recovery of the Timber Road wind renewable energy power purchase agreement (REPA)	• Company's experience in renewable energy • Ohio renewable energy market • Timber Road wind REPA
Frank Graves	Capacity Markets and the Reliability Pricing Model	• Detailed discussion of PJM capacity market

The riders the witnesses are sponsoring in this case help ensure the SSO will provide rate certainty and stability as directed by the Commission in their February 23, 2012 order. The riders in the modified ESP II are consistent with other Ohio utility riders that are in existence. For example, in Case No. 10-388-EL-SSO, Opinion and Order (August 25, 2010), the Commission approved FirstEnergy's most recent ESP case and a proposed Distribution infrastructure rider, DCR, and a rider to recover the costs of FirstEnergy's smart grid plan. In Case No. 11-3549-EL-SSO, Opinion and Order (November 22, 2011), the Commission approved Duke Energy Ohio's ESP case which allowed for an Electric Services Stability Charge rider (which aligns to the AEP Ohio's Retail Stability Rider) and full corporate separation of Duke Energy Ohio's generation from their distribution & transmission assets. The modified ESP II plan properly balances the interests of the Competitive Retail Electric Service (CRES) providers, AEP Ohio, and the interests of its customers.

OHIO REGULATORY BACKGROUND

Q. CAN YOU SUMMARIZE AEP OHIO'S REGULATORY EXPERIENCE SINCE THE ADVENT OF ELECTRIC RESTRUCTURING IN OHIO?

A. Yes. After the passage of SB 3 in 1999, AEP Ohio did not seek recovery of stranded investment costs for its generation fleet. AEP Ohio has provided below market generation rates for the past decade, using its low cost generation assets. By contrast, other Ohio utilities such as the FirstEnergy operating companies recovered billions of dollars of stranded investment costs under SB 3, based on the book value of their generation fleet being much higher than projected market prices.

Following SB 3's market development period (MDP) when generation rates were supposed to be market-based, the Commission ordered EDUs to avoid market-based rates and provide rate stabilization plans (RSPs).[1] The RSPs were to promote rate certainty,

[1] In re DP&L, Case No. 02-2779-EL-ATA, Opinion and Order (September 2, 2003) at 29.

financial stability, and allow for competitive market development prior to charging customers market-based rates.[2] In AEP Ohio's RSP case, the Commission stated:

> At the outset, we will note that AEP proposed a rate stabilization plan because we requested it.[3]

The Commission found a competitive bidding process (CBP) would not be effective and that the Company's proposed rates were more favorable to customers than the market-based rates would be because competitive markets had not adequately developed. [4] That finding was based on the fact that market prices for generation were higher and more volatile than the stable, low prices that AEP Ohio was providing through its regulated generation rates.

Similarly, in 2005, the Commission ordered AEP Ohio to negotiate for the purchase of the Monongahela Power Company (Mon Power), in order to avoid rate shock for Mon Power customers going to market generation rates.[5] The Commission determined that Mon Power customers would be:

> ...far better off under the rates established under the Companies' proposal than by being served at a CBP provided by Monongahela Power." [6]

Even after the passage of SB 221, the Commission adopted "exclusive supplier" provisions inserted into the Ormet and Eramet special contracts over AEP Ohio's objection, whereby Ormet and Eramet were not permitted to shop for ten years (even though AEP Ohio advocated that the customers should retain their ability to shop); the load associated with these contracts was equivalent to the load of more than 500,000

[2] In re Ohio Edison, Case No. 03-1461-EL-UNC, Entry (September 23, 2003) at 4-5.
[3] In re AEP Ohio, Case No. 04-169-EL-UNC, Opinion and Order (January 26, 2005) at 13.
[4] Id. At 14
[5] In re Monongahela Power, Case No. 05-765-EL-UNC, Entry (June 14, 2005)
[6] Opinion and Order (November 9, 2005) at 10.

residential homes.[7] Thus, AEP Ohio's experience during the SB 3 restructuring era was that the Commission would not move toward competition (in an apparent effort to protect customers from higher market-based rates) and acted to prevent utilities from collecting the higher market-based rates, instead pushing the utilities toward a regulated structure. Those same policy concerns led the Commission to conclude in AEP Ohio's first ESP case filed under S.B. 221 that, to take advantage of AEP Ohio's low-cost generation, "it is essential that the plan we approve be one that ... provides future revenue certainty for the Companies, and affords rate predictability for the customers." (*ESP I*, March 18, 2009 Opinion and Order at 72.)

In the same vein, based on its desire to maintain stable, low rates that AEP Ohio was providing and avoid being subject to the market, the Commission strongly encouraged AEP Ohio to operate under the Fixed Resource Requirements (FRR) option for serving AEP Ohio's SSO load as a member of PJM Interconnection LLC (PJM). In its public comments filed at FERC in advance of a FERC Staff Technical Conference on June 7, 2006, this Commission's Staff stated that it "would like to compliment the FERC for accepting the traditional resource requirement approach (the Fixed Resource Requirement option) as a legitimate alternative to RPM." As an FRR entity, AEP Ohio must self-supply its capacity to serve its load (rather than procuring it through the RPM market) and it has the option to establish cost-based charges for CRES providers using its capacity to serve retail customers. AEP Ohio's decision to pursue a cost-based capacity charge is under active consideration in the 10-2929 Commission case. In any case, as further discussed below, AEP Ohio is contractually committed to FRR capacity supply through May 31, 2015.

[7] Case No. 09-119-EL-UNC and 09-563-EL-UNC

Q. PLEASE SUMMARIZE AEP OHIO'S RECENT ESP PROCEEDINGS LEADING UP TO THE CURRENT FILING.

A. Over a year ago on January 27, 2011, AEP Ohio filed their ESP II plan in accordance with Senate Bill 221 (S.B. 221) requiring electric utilities to provide consumers with a SSO, consisting of either an ESP or a market rate offer (MRO). The law provides customers with the right to choose suppliers while the incumbent utility remains obligated as the provider of SSO service for all customers within its service territory regardless of each customer's current choice of supplier. A Stipulation was filed in September 2011 on the original ESP II plan and the Commission approved a modified Stipulation in December 2011. In January 2012, the Stipulation order was amended and then entirely revoked in February 2012 by the Commission. In March 2012, AEP Ohio was ordered by the Commission to provide for market-based pricing for SSO customers in a more expeditious manner than originally proposed in a modified ESP II plan.[8]

OVERVIEW OF THE MODIFIED ESP II

Q. PLEASE PROVIDE AN OVERVIEW OF THE MODIFIED ESP II PLAN.

A. While AEP Ohio understands the prospective alteration of past Ohio policy favoring a regulated structure and the Commission's direction to expedite market pricing, AEP Ohio also requires a reasonable transition plan to be approved by the Commission so as not to financially harm the Company and to fulfill its pre-existing contractual obligations as an FRR entity. Therefore, the Company asks in this modified ESP II filing for the Commission to approve a reasonable and steady path to a fully competitive business structure for AEP in Ohio. AEP Ohio's modified ESP II provides an expeditious path to a fully competitive market without causing serious financial harm to the Company and a

[8] In AEP Ohio Case 10-2376-EL-UNC, et.al, Entry (March 7, 2012) at 6

reasonable solution that aligns to the Company's contractual obligations. To evidence its commitment to adhere to Ohio's new policy directive, AEP Ohio did not pursue an FRR election for the 2015/2016 PJM planning year and, therefore, has submitted notice to PJM of its intent to participate in PJM's Reliability Pricing Model (RPM) for AEP Ohio's load.[9] During the modified ESP II transition plan timeframe, AEP Ohio proposes to corporately separate its generation and marketing functions from its distribution and transmission businesses, to eliminate the AEP Interconnection Agreement (Pool Agreement), to justify the pending cost-based capacity compensation case, and to provide increasing discounts of capacity prices to competitive suppliers for AEP Ohio's generation portfolio. The combination of these directives supports the growth of robust competitive supply options for customers of AEP Ohio and supports the Ohio directive for expedited market-based pricing. While the capacity charge question will be litigated in another case[10], and the new corporate separation application will be filed with the Commission shortly, those separate case outcomes are key factors underpinning AEP Ohio's modified ESP II proposal in this proceeding. Further, with the modified Distribution Investment Rider (DIR) mechanism, the Company will be able to sustain critical investments that benefit customers by maintaining and improving service reliability. Thus, the path will be cleared for competitive market-based auctions to serve AEP Ohio's full SSO energy load beginning January 2015 and its full SSO capacity and energy requirements beginning in June 2015; further, as discussed below, the Company is also proposing as part of the ESP package to conduct a smaller scale SSO energy auction for delivery starting six months after final orders approving the requests are issued in this

[9] Case 10-2929-EL-UNC, filed March 23, 2012
[10] Case No. 10-2929-EL-UNC

proceeding and the corporate separation docket. AEP Ohio's proposals to promote a fully competitive SSO will enhance competition considerably faster than is possible under a market rate option and are simply not possible outside the context of the modified ESP package with a reasonable transition proposed by the Company. This integrated plan represents a significant number of changes to the Company's operating business model, and provides for a balanced outcome for all stakeholders. The modified ESP II assures the availability of reliable supplies of power during the market transition period at reasonable and stable rates for the Companies' generation SSO customers, further enhances competitive opportunities for customers and suppliers, provides stable distribution rates for customers, and provides for enhanced service reliability. For a summary of the modified rate plan, please see Table 2 below:

<u>TABLE 2: MODIFIED ESP II RATE PLAN</u>

Columbus Southern Power Rate Zone				
	Monthly Bills			
Household	Current	Proposed	Change	Tariff
1,000 kWh usage	$121	$128	6%	R-R Winter Bill
2,000 kWh usage	$189	$199	5%	R-R Winter Bill
Small Business				
1,000 kW demand and 100,000 kWh usage	$16,064	$16,354	2%	GS-2 Primary
1,000 kW demand and 300,000 kWh usage	$32,243	$33,187	3%	GS-3 Primary
Industrial Business				
20,000 kW demand and 6 million kWh usage	$436,143	$437,708	0%	GS-4
20,000 kW demand and 12 million kWh usage	$707,544	$716,633	1%	GS-4

Ohio Power Rate Zone				
	Monthly Bills			
Household	Current	Proposed	Change	
1,000 kWh usage	$113	$120	6%	RS Bill
2,000 kWh usage	$212	$223	5%	RS Bill
Small Business				
1,000 kW demand and 100,000 kWh usage	$14,261	$14,999	5%	GS-2 Primary
1,000 kW demand and 300,000 kWh usage	$29,615	$30,857	4%	GS-2 Primary
Industrial Business				
20,000 kW demand and 6 million kWh usage	$478,609	$492,257	3%	GS-4 Transmission
20,000 kW demand and 12 million kWh usage	$712,971	$737,913	3%	GS-4 Transmission

The majority of the rate increases are distribution-related, but please see the testimony of Company witness Roush for the Table 2 details and specific customer impacts. The plan also continues AEP Ohio's existing support for a number of state policies as outlined by Company witness Dias. For an executive summary of the modified ESP II plan, please see Exhibit RPP-1 to my testimony.

CAPACITY PRICES

Q. WHAT ARE THE COMPONENTS OF THE WHOLESALE POWER MARKET?

A. Power markets are primarily comprised of capacity and energy, both of which are needed to provide generation service. Capacity can be described as the maximum physical plant output that a plant or a plant's unit can produce under certain conditions; in other words, it equates to having the generation infrastructure so that it may be available for use and primarily involves fixed costs based on long-term investments. Energy is the actual output that is produced by the plant or unit and primarily involves variable costs. Capacity, usually measured in megawatts (MW), is necessary to ensure that customers have enough energy when they are operating at their highest demand. The energy produced, usually measured in megawatt hours (MWh), is dependent upon the needs of customers across all hours.

In the PJM Reliability Pricing Model (RPM) market, load serving entities can self-supply generation resources (*i.e.*, elect to be an FRR entity) or procure needed capacity through the three-year forward PJM auction. Under the FRR approach, a load serving entity opts out of the RPM market and secures its own capacity to serve its load. Under FRR, CRES providers may supply their own capacity if they participate as an FRR entity and commit resources three years in advance; alternatively, CRES suppliers can avoid long term commitments and simply buy their needed capacity one day at a time from the FRR entity – AEP Ohio (like all of the CRES providers in Ohio have done to date). See the testimony of Company witness Graves for more detail on the PJM capacity market. With the modified ESP II, AEP Ohio has committed to adjust its business plan to a fully competitive energy and capacity market by June 1, 2015 (once its FRR contractual obligation ends) to comply with the Commission's policy directive,[11] though it is important to bear in mind that its willingness to do so is fully dependent upon the total package of inter-related terms and conditions of the proposed ESP. In any case, due to AEP Ohio's contractual obligations as an FRR entity through mid-2015 and AEP Ohio's reliance on prior Commission policy, a reasonable transition period or glide path is needed to wind down the FRR contractual commitment and terminate the Pool

[11] In AEP Ohio Case 10-2376-EL-UNC, Entry(March 7,2012) at 5-6

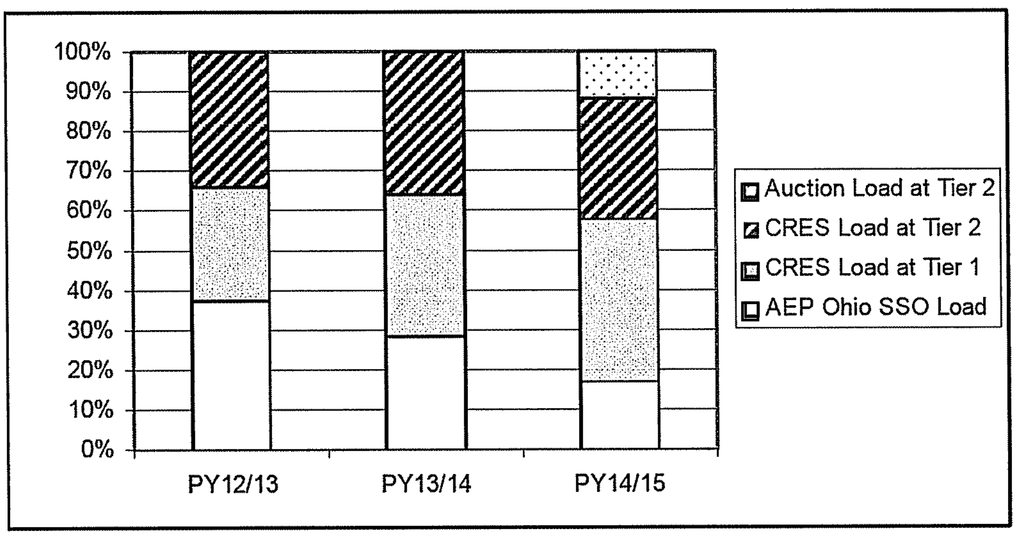
Agreement so the Company can get from "point A" to "point B." For additional detail on the three-year transition plan, see Company witness Nelson.

Q. PLEASE EXPLAIN THE MODIFIED ESP II PROPOSAL WHICH PROVIDES AN INTERIM CAPACITY RATE?

A. The AEP Ohio cost-based capacity charge, as presented in Case No. 10-2929-EL-UNC, is approximately $355/MW day. As part of the integrated package of terms proposed in the modified ESP that would avoid causing serious financial harm to AEP Ohio, the Company proposes to have a two-tiered capacity structure providing for RPM-priced capacity. The first tier is priced at current RPM rates of $146/MW-day to serve approximately 21% of each customer class through December 31, 2012, approximately 31% of each customer class during 2013, and approximately 41% of each class from January 1, 2014 through May 31, 2015. Additionally, for 2012, governmental aggregation initiatives approved in or before the November 2011 elections shall be awarded in 2012 as additional allotments of the $146/MW-day capacity price, while the additional aggregation load will be included within the 31% and 41% set-aside levels in 2013 and 2014, respectively. The remaining capacity prices would be offered at $255/MW-day, a substantial discount from the cost incurred by AEP Ohio to provide capacity. Both tiers of capacity pricing offered as part of the modified ESP II package are significantly below the cost-based rate supported by AEP Ohio in its 10-2929 filing of $355/MW day. Additional detail regarding the capacity pricing proposal is provided below or in the testimony of Company witness Allen.

Q. PLEASE EXPLAIN HOW THE MODIFIED ESP II PLAN AS A WHOLE PROMOTES COMPETITION?

A. As I mentioned above, the modified ESP II provides an accelerated path to fully competitive markets for supplying electricity to AEP Ohio's customers, while respecting AEP Ohio's financial condition and its FRR obligations through May of 2015. By the Commission adopting the modified ESP II plan and agreeing to corporate separation and Pool Agreement elimination, the path is being cleared for competitive auctions to serve AEP Ohio's SSO load. During the ESP II timeframe, AEP Ohio will provide discounted capacity to CRES providers in order to support expedited growth of robust competitive supply options for SSO customers. Further, the Company will delay the Phase-In Recovery Rider (PIRR) and unification of the Fuel Adjustment Clause (FAC) until 2013, as discussed by Company witness Dias. There will be no net changes to overall generation base prices for SSO customers during this transition. In addition, AEP Ohio has seen significant customer switching at the $255/MW-day second tier capacity price. In his testimony, Company witness Allen projects substantially increased shopping based on the second tier capacity pricing:



In short, the modified ESP II provides a rapid transition to complete corporate separation and elimination of the Pool Agreement, allowing for full market pricing in 2015 for competitive generation services, and provides for transparent and stable pricing during the transition period. As proposed, it provides benefits to both CRES providers and customers offering reasonable costs for supply, price stability and increased reliability.

Q. DOES THE MODIFIED ESP PROMOTE COMPETITION IN OTHER WAYS AND ALSO PROMOTE OTHER POLICY OBJECTIVES OF S.B. 221?

A. Yes. A reasonable transition to market for AEP Ohio is needed to truly promote fair competition and to avoid causing serious financial harm to AEP Ohio, which would leave AEP Ohio with no choice but to substantially curtail spending in Ohio and pursue its legal options. Through the proposed ESP, the Company is willing to stimulate shopping by providing discounted capacity and expedite the transition to competition faster than can be legally required, but only if the Commission approves the integrated package of terms proposed in the ESP that will maintain AEP Ohio's financial health. In the guise of advancing competition, some parties will no doubt advocate that AEP Ohio provide additional discounts of its capacity or seek other subsidies, but requiring AEP Ohio to further subsidize CRES providers would represent unfair competition and would harm AEP and its investors. To foster robust and fair competition that will produce low rates for all Ohioans, the Commission should approve the modified ESP, which ensures a reasonable transition to market and fair compensation for AEP Ohio's generation resources that have been *contractually dedicated to serving its* Ohio customers. This Commission should not consider altering AEP Ohio's proposed ESP in a manner that will cause financial harm to the Company. Doing so would force AEP Ohio to significantly reduce its spend in Ohio and inevitably lead to significant job reductions in Ohio (where thousands of AEP employees and contractors work and pay taxes). Such a result would run directly counter to the State policy (in Section 4928.02(N), Ohio Revised Code) to facilitate Ohio's effectiveness in the global economy. By contrast, the proposed modified ESP promotes many policy objectives of SB 221, as is discussed in detail in the testimony of Company witness Dias.

RETAIL STABILITY RIDER (RSR)

Q. WHY IS THE RSR NECESSARY?

A. From the Company's perspective, the need for a RSR charge stems largely from the financial harm to AEP Ohio that would otherwise result from the modified ESP package as a whole. For example, the three-year FRR commitment the Company has with PJM to supply capacity for AEP Ohio load, as well as the obligations that AEP Ohio has under the existing system Pool Agreement, must be considered as AEP Ohio transitions to market. Although the modified ESP II plan commits the company to a full competitive auction bid process for AEP Ohio's SSO by June 1, 2015, the Company must continue to meet its PJM capacity obligations during the interim. The need for a reasonable transition stems from AEP Ohio's contractual FRR and Pool Agreement obligations as well as its reliance on more than a decade of direction from the Commission to avoid subjecting customers to market-based generation rates. Despite its legal commitments, the Company is offering to discount its capacity and will also continue to offer base generation rates at existing levels and bear the going-forward risk of environmental compliance. In exchange for offering these and other benefits of the proposed ESP package, the Company proposes a RSR to decouple generation revenues over the ESP II term ending May 31, 2015. The RSR will provide economic stability and certainty for AEP Ohio, our customers and other stakeholders during the market transition term of the modified ESP II and until corporate separation and the Pool Agreement elimination is complete. Please see the testimony of Company witness Allen for additional details on the RSR.

<u>COMPETITIVE AUCTION BID PROCESS</u>

Q. RECOGNIZING THE COMMISSION'S PRESENT DESIRE TO PROVIDE MARKET-BASED SSO PRICING IN AN EXPEDITIOUS MANNER, WOULD AEP OHIO HAVE CONCERNS ABOUT PROCEEDING IMMEDIATELY TO AN AUCTION-BASED SSO?

A. Yes. As explained by Company witness Nelson in his testimony, AEP Ohio would experience adverse financial risks and impacts that are not acceptable – particularly during the period prior to corporate separation and the AEP Pool being terminated.

Q. WHEN IS AEP OHIO PROPOSING TO IMPLEMENT AN AUCTION-BASED SSO UNDER THE MODIFIED ESP?

A. AEP Ohio must have received final orders providing for the elimination of the Pool Agreement and for full corporate separation in order to implement its proposal to conduct energy auctions for 100% of the SSO load, with delivery beginning January 2015. AEP Ohio would provide capacity support for the auctioned load at $255/MW-day. Within 90 days of receipt of both final orders, AEP Ohio commits to filing a competitive bid auction process (CBP) case for its SSO load. While the details of AEP Ohio's CBP will be forthcoming in another filing, AEP Ohio anticipates that the process will be much the same as other Ohio utility CBP filings approved by the Commission with the benefit of any guidance from the order in these proceedings or developments at the time.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPETITIVE BIDDING PROCESS THAT AEP OHIO WILL BE CONDUCTING FOR THE DELIVERY OF SSO SERVICE IN JANUARY 2015?

A. It is expected that from January 1, 2015-May 31, 2015, a CBP will determine the price of energy for AEP Ohio. Beginning June 1, 2015, a CBP will determine 100% of the SSO energy and capacity prices for AEP Ohio's SSO load. At this time, since AEP Ohio's FRR obligation will be terminated, winning auction suppliers would procure capacity supporting their load from the RPM market. The auction-based process will provide an opportunity for competitive suppliers and marketers to bid for AEP Ohio's SSO load. Customers will continue to have the ability to switch to CRES providers in Ohio, should they desire to do so.

Q. IS AEP OHIO WILLING TO CONDUCT A PARTIAL SSO AUCTION PRIOR TO 2015?

A. For the purpose of facilitating a smooth transition to the full SSO energy auction in January 2015, AEP Ohio is willing to engage in a limited SSO auction as part of the ESP package, as follows. The terms and conditions of such an auction need to be clearly circumscribed up front and AEP Ohio must be made whole to avoid the financial exposure it would otherwise face, including financial impacts of the early auction under the AEP Pool Agreement. Specifically, based on the express condition of financially being made whole, AEP Ohio is willing to conduct an energy-only, slice-of-system auction for 5% of the SSO load, with delivery beginning six months after final orders are both issued adopting the ESP as proposed and the corporate separation plan as filed. The delivery period would extend through December 31, 2014. Details concerning the auction will be addressed immediately following the issuance of final orders.

CORPORATE SEPARATION OVERVIEW

Q. PLEASE EXPLAIN AEP OHIO'S PLAN TO DIVEST ITS GENERATION ASSETS.

A. In conjunction with the requirements of a fully competitive market, AEP Ohio will file with the FERC separate filings to fully separate the AEP Ohio generation and marketing businesses from its transmission and distribution businesses. In one FERC filing, AEP Ohio will ask for the transfer its generation assets at net book value (NBV) to AEP Generation Resources (Genco) by January 1, 2014. This filing will involve the full net book value transfer of all of AEP Ohio's current generation assets to the Genco, a provision that was highlighted by the Commission in their February 23, 2012 Order. Another FERC filing will propose termination and replacement of the Pool Agreement, for which the member companies, including AEP Ohio, provided notice of termination on December 17, 2010 which established a three year termination commitment by January 1, 2014. In another separate application with the FERC, certain generating assets, the Mitchell generating plant and Ohio Power Company's share of Unit No. 3 of the Amos generating plant, will be transferred at net book value from the Genco to Appalachian Power Company (APCo) and Kentucky Power Company (KPCo). Finally, from January

1, 2014-May 31, 2015, the Genco will have an interim power sales agreement (SSO Contract) with AEP Ohio to allow AEP Ohio to meet its FRR capacity requirements and serve its non-shopping retail energy requirements until January 1, 2015. This agreement will require a separate application at the FERC as well. Please see Company witness Nelson for further detail on these FERC filing matters.

Q. PLEASE ADDRESS WHY CERTAIN AEP OHIO GENERATION ASSETS ULTIMATELY WILL BE TRANSFERRED TO APCO/KPCO?

A. For the past 60 years, AEP Ohio and the other generation owning AEP companies in the PJM footprint have participated under the current Pool Agreement. The Pool Agreement allowed for these entities to engage in integrated planning and operation of their power supply facilities and allocate among themselves the generation related costs and benefits. Excluding AEP Ohio, the other AEP-East operating companies are still operating under traditional regulation and utilizing the FRR option. The Pool Agreement is scheduled for termination January 1, 2014. APCo and KPCo have long relied on AEP Ohio generating assets through the Pool Agreement to supply part of the capacity and energy needed to meet their respective state customer load requirements (and APCo and KPCo have long paid for using those assets through capacity equalization charges). The applicable Amos and Mitchell units are physically located in the state of WV, and are of sufficient capacity to cover the expected shortfall (including the required reserve margin) for those FRR companies after the existing pool agreement is terminated. Please see the testimony of Company witness Nelson for further details on these matters.

Q. HOW WILL THE PLANNED RETIREMENTS OF AEP OHIO GENERATION ASSETS IMPACT THE AVAILABILITY OF ADEQUATE CAPACITY FOR OHIO CUSTOMERS?

A. The current AEP Ohio generation asset portfolio will have no direct relationship to the AEP Ohio load, once the transition to corporate separation, Pool Agreement elimination, and market-based capacity/energy procurement is complete. Therefore, any retirements would ultimately be offset by existing capacity or new capacity additions in PJM that could be built by other market participants.

Q. PLEASE EXPLAIN HOW AEP OHIO INTENDS TO ENSURE ADEQUATE CAPACITY ON AN ONGOING BASIS.

A. As outlined above, once the Pool Agreement is eliminated and corporate separation is complete, there will be a SSO Contract between the Genco and AEP Ohio over the ESP II term. To further support the Commission's intent to encourage competition in an expedited manner, from January 1, 2015-May 31, 2015, AEP Ohio will auction the energy component of SSO load. Effective June 1, 2015, AEP Ohio will use a CBP for supply of capacity and energy supporting SSO load in the same manner as other Ohio electric utilities do today. The assurance of adequate capacity will become a function and obligation of PJM. Please see the testimony of Company witness Graves who details PJM's RPM process.

<u>OTHER OPTIONS</u>

Q. HAS AEP OHIO REVIEWED OTHER OPTIONS FOR AN ESP II PLAN?

A. Yes. AEP Ohio looked at an alternative option to provide the economic benefits of shopping directly to the customers as a shopping credit over the modified ESP II term ending May 31, 2015. At a single cost-based price for capacity charged to CRES providers over the ESP II term, AEP Ohio would implement no base generation increase, no RSR, and would provide a meaningful shopping credit to customers to switch their generation service. This option would allow for Ohio customers to experience the true benefits of shopping and the market, but will directly limit the margins of the CRES providers and of AEP Ohio. Please see the the testimony of Company witness Allen for details on this option.

AGGREGATE MARKET RATE OFFER (MRO) TEST

Q. DOES THE ESP II PASS THE MRO TEST IN THE AGGREGATE?

A. Yes. I have been advised by counsel that an application for an ESP should be approved if the Commission finds that the ESP II, including its pricing and all other terms and conditions, is more favorable in the aggregate as compared to the expected results that a market rate offer would provide. As the Commission has done in other ESP cases (including the recent FirstEnergy and Duke Energy Ohio cases, as well as AEP Ohio's ESP I proceeding), it should not rely solely on the price test analysis of the aggregate MRO test in reviewing the modified ESP II proposal but should also give serious consideration to qualitative benefits of the proposed ESP. Company witness Thomas shows how the elements of the modified ESP II support favorable aggregate MRO test results.

CONCLUSION

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXECUTIVE SUMMARY OF THE MODIFIED ESP II FILING

- June 1, 2012 – May 31, 2015 is the ESP term
- January 1, 2015 – May 31, 2015 begins energy auction for 100% of SSO load
- June 1, 2015 begins full delivery and pricing of AEP Ohio SSO service through competitive auction bid process (CBP)
- Energy auction for 5% of SSO load with delivery starting six months after final orders in ESP and corporate separation cases.
- Discounted capacity prices for CRES providers over the ESP term
- The overall request in this ESP has minimal impact on customers' rates
  - On average over the three-year period, an AEP Ohio retail and commercial customer will see an annual increase to the bill of approximately 3%
  - The change in rates includes no base generation increase but allows for collection of costs that AEP Ohio incurred but was unable to collect for a number of years

AEP OHIO MODIFIED ESP II RATES (cents/kWh)

	Current Rates 2012	June 2012 - May 2013		June 2013 - May 2014		June 2014 - December 2014	
	cents/kWh	cents/kWh	%	cents/kWh	%	cents/kWh	%
Base Generation	2.10	2.25	7%	2.25	0%	2.25	0%
Fuel Adjustment Clause	3.61	3.61	0%	3.60	0%	3.60	0%
Environmental	0.16	-	na	-	0%	-	0%
Total Generation	**5.86**	**5.86**	0%	**5.85**	0%	**5.85**	0%
Transmission	0.80	0.80	0%	0.80	0%	0.80	0%
Distribution**	2.13	2.32	9%	2.36	2%	2.39	1%
Phase-In Rider	-	-	0%	0.31	na	0.31	0%
Retail Stability Rider	-	0.20	na	0.20	0%	0.20	0%
Total	**8.79**	**9.19**	**5%**	**9.54**	**4%**	**9.56**	**0%**

** AEP Ohio summary from Exhibit DMR-1. Includes rate mechanisms as outlined in Exhibit DMR-4

EXECUTIVE SUMMARY OF THE MODIFIED ESP II FILING

- The overall request complies with order for expeditious transition to market-based generation rates in Ohio
  - Elimination of Interconnection Pool Agreement (Pool Agreement)
  - Corporate separation of AEP Ohio's generation and marketing assets from its distribution and transmission assets
  - Offers AEP Ohio capacity at a price that is currently below $/MW-day cost to AEP
- Proposed rate plan offers price certainty to AEP Ohio customers and to CRES providers
- Proposed riders in ESP II (See Exhibit DMR-4):
  - RSR: mitigates financial harm to the Company of offering integrated ESP package of terms and conditions, including capacity discount pricing
  - DIR: allows for continuation of distribution investment measures to support reliability improvements
  - AER: recovery mechanism to support Commission staff request for Alternative Renewable Energy Credit tracking mechanism
  - GRR: placeholder mechanism for Turning Point project
- Continue current riders through ESP II term June 1, 2015 (See Exhibit DMR-4):
  - Universal Service Fund Rider, Deferred Asset Recovery Rider, kWh Tax Rider, Residential Distribution Credit Rider, Pilot Throughput Balancing Adjustment Rider, Transmission Cost Recovery Rider, EE/PDR, Economic

EXECUTIVE SUMMARY OF THE MODIFIED ESP II FILING

Development Rider, ESRR, gridSMART, Electronic Transfer Rider, Renewable Energy Credit Purchase Offer Rider, Renewable Energy Technology Program Rider, Fuel Adjustment Clause (unified FAC begins 2013)

- Miscellaneous riders & provisions (See Exhibit DMR-4):
  - Phase In Recovery Rider (begins 2013 with unified FAC)
  - Storm Damage Recovery Mechanism
  - Pool Termination Provision – if necessary
- Eliminated riders (See Exhibit DMR-4):
  - Emergency Curtailable Service Rider, Energy Price Curtailable Service Rider, Environmental Investment Carrying Cost Rider (combined with base rates)

EXHIBIT ____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY OF
FRANK C. GRAVES
IN SUPPORT OF AEP OHIO'S
MODIFIED ELECTRIC SECURITY PLAN

Filed: March 30, 2012

SC EXHIBIT 18

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
FRANK C. GRAVES
ON BEHALF OF
OHIO POWER COMPANY

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

A. My name is Frank C. Graves. I am a Principal at *The Brattle Group*, where I am also co-leader of the Utility Practice Area. My office is located at 44 Brattle Street, Cambridge, MA, 02138. My resume is attached to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will explain why it is reasonable for the PUCO and the customers of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) (also referred to as AEP Ohio) to be confident of the supply adequacy of their power supply when these AEP companies switch from being Fixed Resource Requirement (FRR) suppliers of capacity to relying on capacity supplied via PJM's Reliability Pricing Model (RPM) auctions. This explanation will include a description of how PJM's capacity markets operate, how they have performed, and what effects potential coal plant retirements could have.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND RELEVANT EXPERTISE?

A. I have an M.S. in Management from the MIT Sloan School of Management with a concentration in finance, and a B.A. in Mathematics from Indiana University. I have been consulting to the electric industry for over 30 years on matters related to long term resource planning, pricing, prudence, risk management, fuel and power procurement, environmental compliance, market forecasting and performance, regulatory policy impacts, and other long term influences on utility assets, costs, and obligations.

I have appeared numerous times as an expert witness before state and federal courts and regulatory bodies, including the Federal Energy Regulatory Commission (FERC), and utility commissions (or administrative law judges for them) in Ohio, Illinois, Pennsylvania, Wisconsin, Kentucky, Michigan, Massachusetts, Vermont, New York, New Jersey, Virginia, Texas, California, New Mexico, and Utah to explain tradeoffs and likely costs and benefits of utility activities and decisions. I participated as a witness on behalf of these same AEP companies in the contemporaneous PUCO rehearing of their proposal for capacity pricing to Competitive Retail Electric Suppliers. I have also been a witness in state and federal courts regarding contract disputes between energy companies. A detailed description of my expertise is attached as Appendix A to this testimony.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND OPINIONS.

A. The PJM capacity markets have been functioning effectively since 2007. During that time, they have brought forward a large amount of new capacity resources, and have done so at prices generally below the annualized Net Cost of New Entry (Net CoNE) in most regions of PJM, including the region in which CSP and OPCo are located. These auctions are designed to assure that there is an adequate supply reserve margin three years forward, and in that regard they have succeeded very well. This result has been achieved by eliciting the participation of many kinds of capacity resources, including demand response, plant life extensions, transmission expansions, and new generation stations.

Despite likely coal plant retirements over the next few years (due to low gas prices and environmental retrofit obligations), it does not appear that there is any reason to fear a supply adequacy problem. PJM has more than target reserves at present and likely retirements are partly offset by announced new entry. Furthermore, the RPM auctions occur far enough in advance that even if a pending shortfall appeared likely, there would be sufficient time for new resources to be developed.

Q. PLEASE DESCRIBE THE PJM CAPACITY MARKET AND HOW THE RPM WORKS.

A. RPM has several components: a demand curve for future supply adequacy (called the Variable Resource Requirement, or VRR), an obligation for all capacity resources in PJM to bid into the Base Residual Auctions (BRAs) held in May every year for capacity three years forward, and an obligation for all PJM load serving entities (LSEs) that are not FRR entities to pay for the RPM capacity at the market clearing price in those BRAs, for all of their coincident peak load plus a reserve margin.

Q. HOW DOES THE VRR CURVE REFLECT DEMAND FOR RELIABILITY RESOURCES?

A. The VRR demand curve is not literally a market-inferred estimate of customer preferences for supply reliability, but rather it is a constructed curve that assumes the value of reliability is equal to the Net CONE if the planning reserves in PJM are equal to the PJM target reserve margin (typically around 15-18%, depending on supply mix and market circumstances). The curve slopes downward through this point, such that if the available supply is larger than this target, the deemed value of reliability (expressed in units of dollars per MW day) is less than Net CONE, and it is more than that if supply is below target.

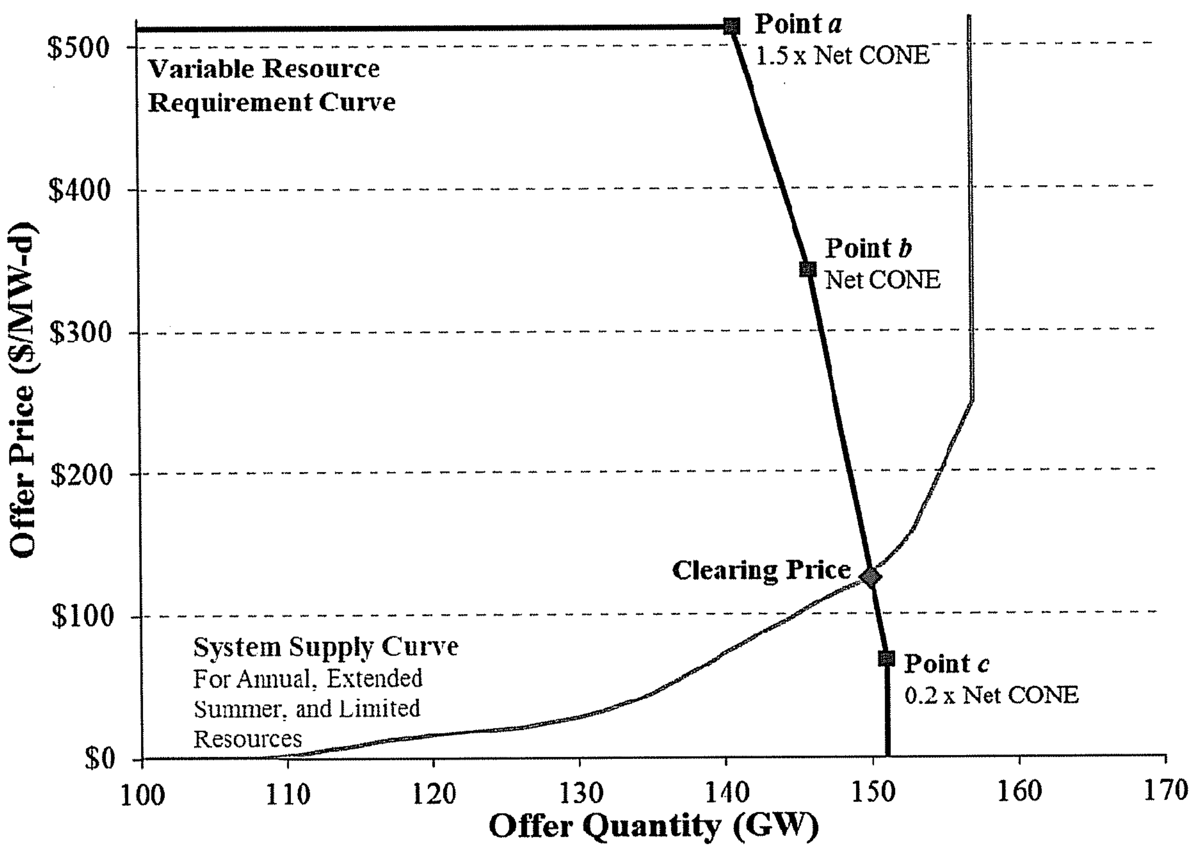
Q. PLEASE EXPLAIN CONE AND NET CONE IN MORE DETAIL.

A. CoNE is the cost of new entry for whatever technology is determined to be the efficient long run type of new capacity needed if/when supply reserves are below target. For several years, this has been determined to be a gas-fired combustion turbine, i.e. a "peaker", as is commonly used throughout the industry for supply adequacy planning purposes. The CoNE amount is the annual carrying costs for recovering the investment and fixed operating costs of such a new unit. Net CoNE is CoNE reduced by the operating margins (contributions to fixed costs) that can be expected from energy sales into PJM at LMPs (locational marginal prices) above the variable operating cost of the unit, plus revenues from ancillary services markets. PJM estimates those margins by using a three year average of historical LMPs and fuel prices.

Q. HOW DOES NET CONE DETERMINE THE LOCATION OF THE VRR?

A. This is shown in the graph below showing the VRR for the last BRA (2014/15). The Net CoNE anchors the VRR at the target reserve margin plus 1%, while two points are set around that: the lower one at 5% above target reserve margin, where reliability demand is presumed to be 20% of Net CoNE, and a higher one at target reserves less 3%, where reliability demand is presumed to be 150% of Net CoNE. Outside of those bounds, the VRR does not change.

RPM Capacity Supply and Demand in 2014/15 Base Auction



Source: Figure 3, p.6., "Second Performance Assessment of RTO's Reliability Pricing Model", The Brattle Group, Aug. 26, 2011

Q. PLEASE EXPLAIN THE CLEARING PRICE POINT DEPICTED IN RED IN THE ABOVE GRAPH.

A. The clearing price is the point where the supply bids in the BRA from all the capacity resources in PJM intersect the VRR. This becomes the RPM price for that future year. The supply curve itself is built up from bidders' offers to supply (which can include the costs they need to recover for future environmental compliance). Supply bidders include existing and new power plants, demand resources (DR, including curtailable load and energy efficiency resources), and transmission upgrades.

It is important to note that if enough capacity is available and offered at low prices, the capacity market can clear (as seen above) with more reserves than are needed to satisfy the target. As demonstrated later below, this has been the case for the last several auctions.

Q. HOW WELL HAS RPM WORKED FOR MAINTAINING PJM'S SUPPLY ADEQUACY?

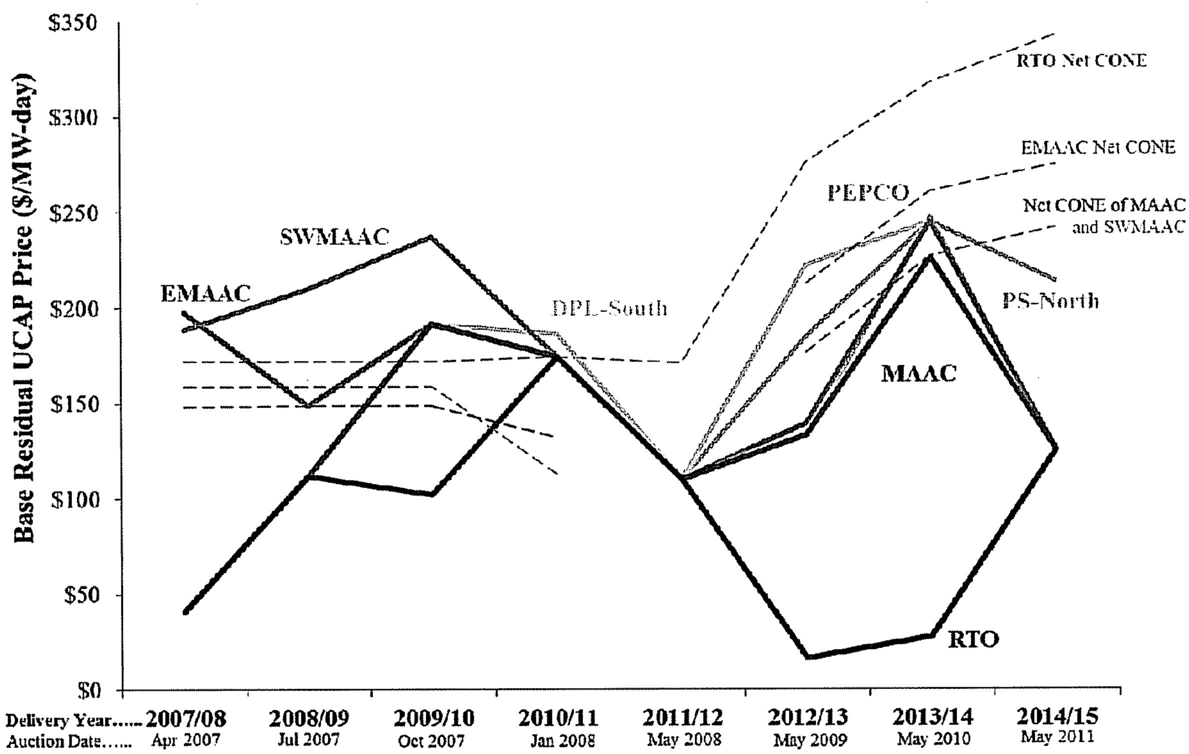
A. The purpose of RPM is to assure resource adequacy over the next three years. This horizon is sufficient because for longer periods of time, it becomes more uncertain as to what level (and locations, etc.) of reserve resources will be needed, and it is also possible to develop some types of new resources within a few years. RPM is <u>not</u> trying to address the question of what new resources could be economically or socially attractive over a very long period of time. Thus, it does not address environmental considerations, long term energy benefits or risks from alternative fuel mixes, new technology development, or local jobs and infrastructure goals. Those may be important questions, but they are beyond the scope of RPM. It is solely designed to assure that sufficient deliverable power (or reliable demand curtailment) is available over the next three years. In this regard, RPM has worked very well – a finding supported empirically by several facts:

- RPM prices have been below Net CoNE in most regions of PJM for nearly all of the years since inception (in 2007). This means RPM has elicited means of assuring supply adequacy at a cost below the cost of building new peakers.
- The BRA auctions have cleared more than enough capacity to meet target reserves, and are so positioned through 2014/15 today.
- RPM has brought forth roughly 30,000 MW of capacity that might not have otherwise been economical and available in PJM, including significant quantities of DR.

Q. HOW HAS THE RPM PRICE IN THE AEP REGION COMPARED TO NET CONE?

A. The western part of PJM is usually unconstrained (in terms of having transmission limits on using all of the available capacity in the pool). Accordingly, it is relevant to consider the prices in the rest of PJM region (which excludes those portions in the east that tend to be transmission-constrained Local Deliverability Areas, or LDAs). These results are seen in the graph below, using the lines labeled "RTO".

Resource Clearing Process Base Residual Auctions



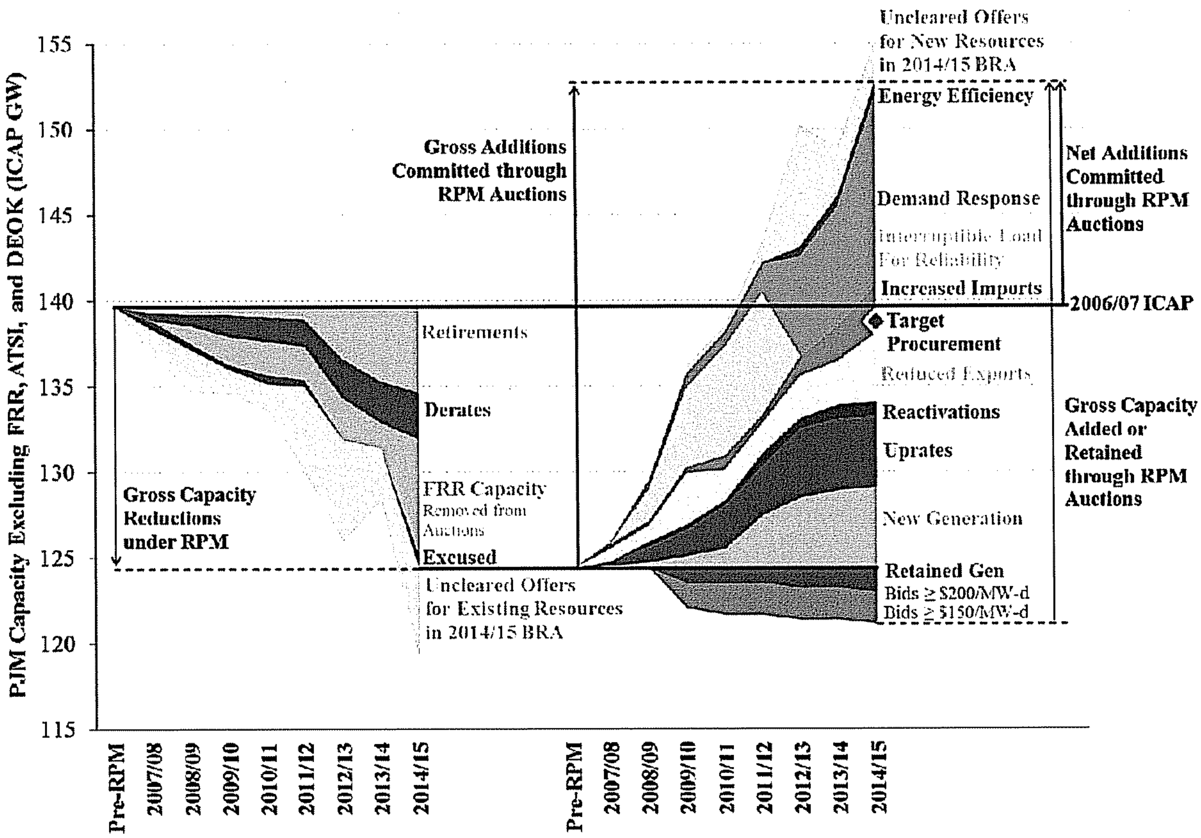
Source: Brattle 2011 RPM report , op.cit., Figure 5, p.12

This graph shows that the capacity prices in the RTO region have generally been well below $150/MW-day, while Net CoNE has been in a range from about $170 to nearly $350/MW-day most recently. (This recent Net CoNE price is quite close to the $355 embedded cost of capacity AEP is proposing in Case 10-2929-EL-UNC if its ESP II plan is not accepted in this proceeding.)

Q. IS THIS PATTERN OF RPM PRICES BEING BELOW NET CONE LIKELY TO BE A STANDARD, PERSISTENT FEATURE OF THAT MARKET?

A. Probably not in the long run. To date, RPM has attracted lots of new kinds of capacity resources that have lower incremental costs than a new peaker, such as life extensions for existing plants, DR from curtailable customers, and plant uprates. A profile of the mix of these additions over time is shown below. This graph shows that RPM has attracted almost 30,000 MW of new resources since 2007, offsetting approximately 15,000 MW of retirements and derates, and more than accommodating demand growth requirements. A significant portion of this new supply, especially in the past three auctions, has been DR capacity, which now accounts for almost 13000 MW of PJM's reserves. Indeed, the feasibility of bidding DR into RPM has probably fostered and encouraged DR above and beyond the levels that might have been observed solely due to state or utility-specific conservation goals and mandates.

RTO Net Capacity Additions Committed in RPM Auctions



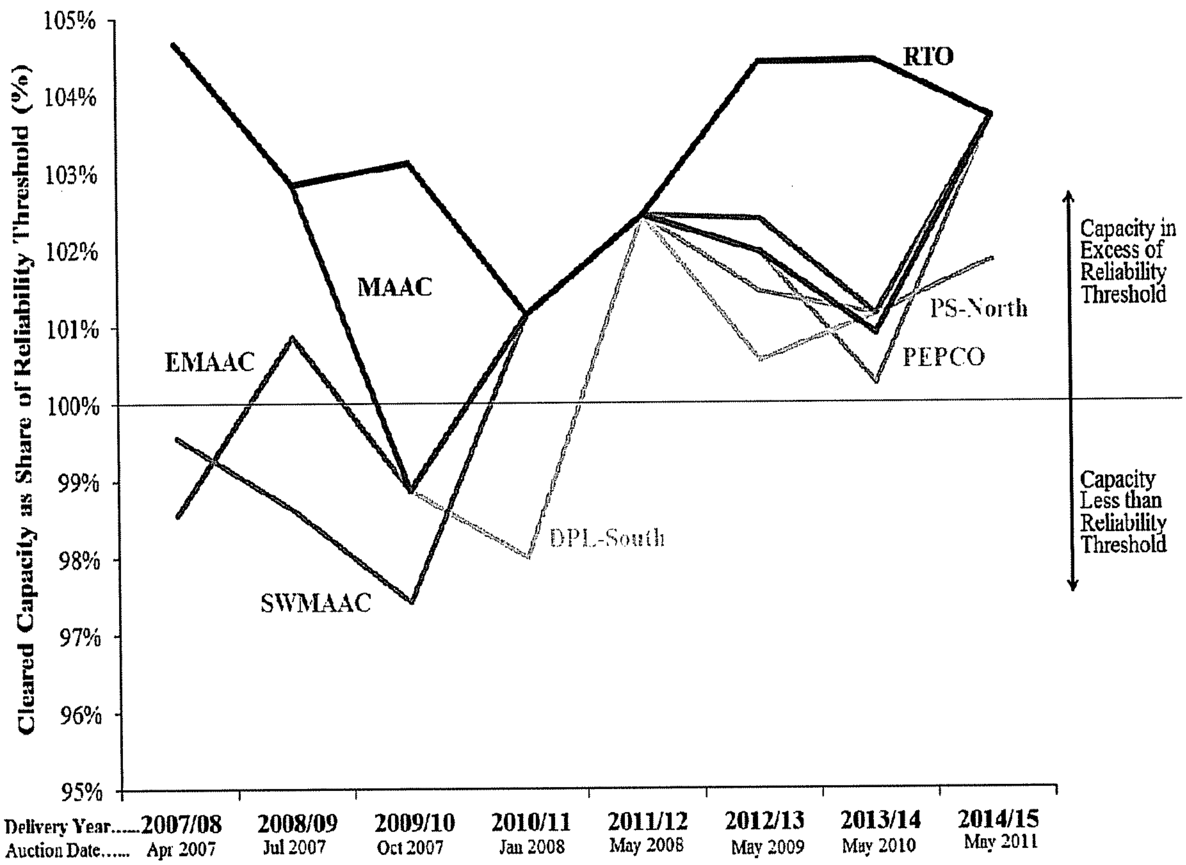
Source: Brattle 2011 RPM report, op. cit., Fig. 10, p. 38

It is very attractive that these types of new capacity resources have been forthcoming, but there probably is a limit to the continuing growth in supply of such previously untapped solutions to supply adequacy management.

Q. TO WHAT EXTENT HAS THE CLEARED CAPACITY EXCEEDED TARGET RESERVE MARGINS?

A. The RTO region in which AEP Ohio will participate has typically had 2-5% more cleared capacity than was needed to meet reserve targets. This is seen below in the black line. Moreover, this just reflects the cleared capacity. More capacity is generally offered into the auctions than is accepted (because the acceptance stops where the supply curve crosses the VRR, even if there are other, higher cost offers on the residual portion of the supply curve).

Reliability Margins Clearing in Base Residential Auctions



Source: Brattle 2011 RPM report, op. cit., Fig. 4., p. 11.

Q. WHAT IS YOUR UNDERSTANDING OF PJM'S SUPPLY ADEQUACY OUTLOOK?

A. Based on NERC's Long Term Resource Adequacy (LTRA) predictions in late 2011 for the summer of 2016 (without any un-announced coal retirements), PJM as a whole will have about 20-23% reserve margin over a projected peak of 168 GW.[1] (PJM today has about 196 GW of installed capacity, projected in the LTRA to grow about 200-206GW by 2016.) This means there will be surplus capacity of about 8-13 GW relative to a 15.3% target, and reserves will not fall below reference margin levels until 2020 or 2021.[2] This assessment is encouraging, but it does not include either the reductions from unannounced potential retirements or new generation. (This and other PJM-wide reserve margin statistics are not specific to the AEP Ohio region. However, because the AEP Ohio region is not a constrained LDA, it can generally be supported for supply adequacy purposes by generation anywhere in PJM.)

Q. WHAT ARE THE POTENTIAL COAL PLANT RETIREMENTS FOR PJM?

A. This is a difficult question to answer definitively, but there are several studies pointing in roughly the same direction. These include:

- NERC's 2011 LTRA included a section of analysis on the impacts of pending environmental regulations, which found that for PJM these added compliance costs could induce 3-7 GW of coal retirements by 2018, in addition to then already announced retirements of about 8 GW.[3] This degree of retirements would result in PJM reserve margins staying above the 15% target level until at least 2017.

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1 NERC 2011 Long Term Resource Adequacy, p. 56
2 NERC 2011 LTRA, p. 65
3 NERC 2011 LTRA, pp. 128 & 129.

- *The Brattle Group's* December 2010 study "Potential Coal Retirements under Emerging Environmental Regulations" projected 8-15 GW of retirements in PJM. However, natural gas and wholesale power prices have dropped considerably from that time, such that we now expect PJM retirements could be closer to 20 GW -- though we have not completed updating that analysis for current market conditions and announced retirements.
- PJM's August 26 2011 study entitled "Coal Capacity at Risk for Retirement in PJM" found that overall, PJM had roughly 23 GW, or roughly 29% of all coal plants had an age greater than 40 years, a size smaller than 400MW, and lacked likely necessary environmental controls. Evaluating the roughly 64 GW of coal in PJM (excluding plants in the ATSI and Duke regions) against 2007-10 energy margins, it found 11-19 GW of coal outside MAAC was likely to retire or at risk for retirement due to requiring additional revenues greater than half (or more) of Net CoNE. Nonetheless, it noted that the even with some coal units already not participating in RPM due to planned retirements, the RTO was carrying a 19.6% reserve margin for 2014/15 and no overall supply adequacy risk was foreseen. Even with at-risk retirements, PJM's reserve margin for 2014/15 was expected to be above the 15.3% target, due to offsetting entry by new units. [4]
- Various recent trade press reports indicate that about 11 GW of coal has already announced retirement in PJM (including FE's announced retirements), of which about 10 GWs are in western PJM (including AEP zone).

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[4] "Coal Capacity at Risk for Retirement in PJM," Aug.26, 2011, p. iv and p.34.

- The PJM 2011 State of the Market (SoM) Report – indicates that about 18.9 GW of overall retirements under "planned deactivations" are expected by 2019 (most of it in 2015), including an expectation of 5191 MW in the AEP zone.[5]

Q. WHAT IS THE LEVEL OF ANNOUNCED OR LIKELY NEW ENTRY?

A. There is quite a bit of new generation being developed. The 2011 SoM indicates that 5000 MW of new capacity came online in 2011, including four gas CCs and one coal plant, all greater than 500 MWs each.[6] The same economic forces that are making coal plants struggle are attracting entry by new gas fired generation. There are almost 35,000 MWs of new CCs in the queue for interconnection permits, of which 4355 is in the AEP zone.[7] Of course, much of this will not be built, but it is likely that a meaningful portion of it will be built. For instance, Ventyx data indicates that about 3 GW of new generation capacity are currently under construction, while an additional 626 MW have their sites prepared and 6535 MW have been permitted.[8]

It is also important to recall that these development statistics only describe plants requiring upgraded transmission interconnections, not other new kinds of RPM capacity resources that are likely to naturally respond to retirements and any upward pressure that places on future capacity prices.

Q. ALTOGETHER, WHAT IS YOUR ASSESSMENT OF THE LIKELY IMPACT OF THESE RETIREMENTS AND ADDITIONS ON SUPPLY ADEQUACY?

[5] Monitoring Analytics, "2011 State of the Market Report for PJM-Vol 2", pp. 291-2.
[6] PJM SoM 2011 Report, p. 286.
[7] PJM SoM 2011 Report, p. 288.
[8] Ventyx Generating Unit Capability Database, Brattle analysis.

A. Taking all of these forecasts and changing market conditions into account, it appears that 5-9 GWs of new generation are likely to come online in PJM over the next 3-4 years, which would offset some of the 15-20 GW of likely coal retirements over that same time frame. But given that PJM is positioned to have around 8-13 GWs in excess of its reserve target without these changes, including them indicates PJM would reach or fall a just bit below its 15% reserve margin levels in the 2016/17 time frame. This is not a cause for concern. The RPM process has routinely elicited changes in supply of several thousand GWs per year. On balance, I am not concerned about a supply adequacy shortfall. It is possible that RPM prices will rise to reflect less surplus capacity than has prevailed in the past, but if so, that is an efficient outcome to signal need and encourage conservation in the long run.

Q. DOES THE TRANSFER OF THE MITCHELL AND AMOS UNITS TO APCO AND KPCO AFFECT SUPPLY ADEQUACY FOR AEP OHIO?

A. I do not believe this should have any adverse effects. Company witness Nelson explains that AEP Ohio has been selling capacity to the rest of the AEP Pool for the past few years, in roughly the same quantities as the size of those transferred units. Specifically, AEP Ohio sold almost 2500 MW in 2010 and about 2150 MW in 2011. By comparison, the Mitchell plus Amos 3 capacity is 2417MW (average annual DNR). As described by Company witness Powers, unless this capacity is transferred to Appalachian Power and Kentucky Power, those companies will not be able to satisfy their FRR requirements (which were previously satisfied for all of the AEP Pool as a whole, i.e., using the same capacity that is now being transferred.)

For one year after this transfer, which occurs at the beginning of 2014 (before AEP Ohio switches over to RPM in 2015), AEP generation will still be used to satisfy AEP Ohio's FRR obligations (expiring in 2015). Thereafter, AEP Ohio will have its supply adequacy needs satisfied with RPM capacity. From that point on, it is no longer relevant or necessary to question whether AEP Ohio owns as much capacity as it demands or not. It is only important that PJM have enough capacity in aggregate for AEP Ohio and all the other utilities in that region – which as was explained above, looks very likely.

Q. HOW DOES YOUR SUPPORT HERE FOR RPM'S EFFICACY RELATE TO YOUR SUPPORT FOR AN EMBEDDED COST CAPACITY PRICE TO CRES PROVIDERS IN THE ASSOCIATED PROCEEDING?

A. My testimony in support of a cost-based capacity price to Competitive Retail Electric Service (CRES) providers is not based on any different viewpoint regarding RPM. As explained above, RPM has been designed to address near term resource adequacy, not to minimize the cost or riskiness of service over longer horizons such as decades or the whole life of generation assets that a utility and its regulators may have used for resource planning. AEP Ohio built or acquired its generation fleet under that latter criteria and protocols, for the purposes of being an integrated utility and then one under FRR. That obligation continues contractually through 2015, and in my view properly entitles AEP to cost recovery on those investments. Such cost recovery would not occur under RPM pricing for capacity to CRES providers. However, AEP Ohio is now willing to transition to RPM over the remaining years of FRR obligations, and I believe it can do so with no adverse effects on supply adequacy to its customers.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

Mr. Frank Graves is a Principal of *The Brattle Group* who specializes in regulatory and financial economics, especially for electric and gas utilities. He has assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. He also provides consulting and expert witness support for commercial litigation matters, such as contract disputes and securities fraud proceedings. He has testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning (IRPs), the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified for companies in regard to contract damages estimation, securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

AREAS OF EXPERTISE

- *Utility Planning and Operations*
- *Regulated Industry Restructuring*
- *Market Competition*
- *Electric and Gas Transmission*
- *Financial Analysis*

EXPERIENCE

Utility Planning and Operations

- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.

- Merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.

- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.

- Wind resources are becoming a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied *Brattle*'s risk modeling capabilities to simulate the impacts of wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. He has also assessed the amount and costs of additional ancillary services that may be required to successfully integrate large quantities of wind generation on the transmission grid.

- The potential introduction of environmental restrictions or fees for CO_2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.

- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.

- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.

- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.

- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.

- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.

- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.

- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.

- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.

- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.

- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO_2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.

- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.

- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.

- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company's power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.

- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.

- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.

- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.

- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory *pro forma* financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).

- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial *pro forma* simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.

- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Restructuring

- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.

- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.

- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have lead to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.

- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.

- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.

- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.

- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.

- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.

- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.

- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.

- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.

- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.

- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.

- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.

- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.

- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a large Western utility.

- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.

- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.

- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.

- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The *Brattle* team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.

- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.

- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

Financial Analysis

- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.

- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equityholder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.

- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.

- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.

- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.

- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.

- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.

- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.

- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.

- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.

- For a major electronic and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.

- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.

- The energy and telecom industries have been plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.

- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.

- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.

- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.

- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.

- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.

- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.

- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, *e.g.*, based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.

- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.

- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.

- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.

- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.

- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.

- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association
- International Association for Energy Economics

TESTIMONY

Direct testimony on behalf of Columbus Southern Power Company and Ohio Power Company before the Public Utilities Commission of Ohio in the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929 -EL-UNC, August 31, 2011.

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Numbers A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket Number M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean Power LLC, Pillar Fund LLC and Accord Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

Rebuttal report in regard to appropriate discount rates for different phases of long-term leveraged leases, on behalf of Wells Fargo & Co. and subsidiaries, Docket No. 06-628T, January 15, 2009.

Oral and written direct testimony regarding resource procurement and portfolio design for Standard Offer Service, on behalf of PEPCo Holdings Inc. in its Response to Maryland Public Service Commission, Case No. 9117, October 1, 2008 and December 15, 2008.

Direct testimony regarding considerations affecting the market price of generation service for Standard Service Offer (SSO) customers, on behalf of Ohio Edison Company, *et al.*, Docket 08-125, July 24, 2008.

Direct testimony in support of Delmarva's "Application for the Approval of Land-Based Wind Contracts as a Supply Source for Standard Offer Service Customers," on behalf of Delmarva Power & Light Company before the Public Service Commission of Delaware, July 24, 2008.

Oral direct testimony in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, on behalf of plaintiff Dairyland Power Cooperative before the United States Court of Federal Claims (No. 04-106C), July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service, as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Oral direct testimony regarding the economic substance of a cross-border lease-to-service contract for a German waste-to-energy plant on behalf of AWG Leasing Trust and KSP Investments, Inc before U. S. District Court, Northern District of Ohio, Eastern Division, Case No. 1:07CV0857, January 2008.

Direct testimony regarding portfolio management alternatives for supplying Standard Offer Service, on behalf of Potomac Electric Power Company and Delmarva Power & Light Company before the Public Service Commission of Maryland, Case No. 9117, September 14, 2007.

Direct testimony in regard to preconditions for effective retail electric competition, on behalf of New West Energy Corporation before the Arizona Commerce Commission, Docket No. E-03964A-06-0168, August 31, 2007.

Direct and rebuttal testimonies regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider, on behalf of Oklahoma Gas & Electric Company (OG&E) before the Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007.

Testimony in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders, on behalf of defendant Mark Kaiser before U.S. District Court of New York SI:04Cr733 (TPG).

Rebuttal testimony on proposed benchmarks for evaluating the Illinois retail supply auctions, on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading before the Illinois Commerce Commission Docket Number 06-0800, April 6, 2007.

Direct and rebuttal testimonies on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis, on behalf of the U.S. Department of Justice before the United States District Court, Southern District of Texas, Houston Division, Criminal Number H-03-217, September 12, 2006.

Direct and rebuttal testimony on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006.

Direct testimony regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification, on behalf of the Deutsche Bank Entities before the United States District Court, Southern District of Texas, Houston Division, Docket No. H-01-3624, February 2006.

Expert and Rebuttal reports regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract, on behalf of Pacific Gas and Electric Company before the United States Court of Federal Claims, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005.

Direct testimony regarding the appropriate load caps for a POLR auction, on behalf of Midwest Generation EME, LLC before the Illinois Commerce Commission, Docket No. 05-0159, June 8, 2005.

Affidavit regarding unmitigated market power arising from the proposed Exelon – PSEG Merger, on behalf of Dominion Energy, Inc. before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, April 11, 2005.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on the value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Northeast Utilities Service Company, Docket No. ER01-2584-000, July 13, 2001, in regard to competitive impacts of a proposed merchant transmission line from Connecticut to Long Island.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, before the Federal Energy Regulatory Commission (FERC), Docket No. ER96-1551-000, March 26, 2001, to provide an updated application for market based rates.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, *In the Matter of Customer Billing Arrangements*, Case 99-M-0631.

Supplemental Direct and Reply Testimonies of Frank C. Graves and A. Lawrence Kolbe (jointly) on behalf of Southern California Edison Company, Docket Nos. ER97-2355-00, ER98-1261-000, ER98-1685-000, November 1, 1999, regarding risks and cost of capital for transmission services.

Expert report before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, *Connecticut Yankee Atomic Power Company, Plaintiff v. United States of America*, No. 98-154 C, June 30, 1999, regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Maine Yankee Atomic Power Company, *Maine Yankee Atomic Power Company, Plaintiff v. United States of America*, No. 98-474 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Yankee Atomic Electric Company, *Yankee Atomic Electric Company, Plaintiff v. United States of America*, No. 98-126 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Prepared direct testimony before the Federal Energy Regulatory Commission on behalf of National Rural Utilities Cooperative Finance Corporation, Inc., *Cities of Anaheim and Riverside, California v. Deseret Generation & Transmission Cooperative*, Docket No. EL97-57-001, March 1999, regarding cost of service for rural cooperatives versus investor-owned utilities, and coal plant valuation.

Expert report and oral examination before the Independent Assessment Team for industry restructuring appointed by the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation, January 1999, regarding the cost of capital for generation under long-term, indexed power purchase agreements.

Oral testimony before the Commonwealth of Massachusetts Appellate Tax Board on behalf of Indeck Energy Services of Turners Falls, Inc., *Turners Falls Limited Partnership, Appellant vs. Town of Montague, Board of Assessors, Appellee*, Docket Nos. 225191-225192, 233732-233733, 240482-240483, April 1998, regarding market conditions and revenues assessment for property tax basis valuation.

Direct and joint supplemental testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Electric Company and Metropolitan Edison Company, No. R-00974009, *et al.*, December 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Direct Testimony before the Pennsylvania Public Utilities Commission on behalf of UGI Utilities, Inc., Docket No. R-00973975, August 1997, regarding forecasted wholesale market energy and capacity prices.

Testimony before the Public Utilities Commission of the State of California on behalf of the Southern California Edison Company, No. 96-10-038, August 1997, regarding anticompetitive implications of the proposed Pacific Enterprises/ENOVA mergers.

Direct and supplemental testimony before the Kentucky Public Service Commission on behalf of Big Rivers Electric Corporation, No. 97-204, June 1997, regarding wholesale generation and transmission rates under the bankruptcy plan of reorganization.

Affidavit before the Federal Energy Regulation Commission on behalf of the Southern California Edison Company in Docket No. EC97-12-000, March 28, 1997, filed as part of motion to intervene and protest the proposed merger of Enova Corporation and Pacific Enterprises.

Direct, rebuttal, and supplemental rebuttal testimony before the State of New Jersey Board of Public Utilities on behalf of GPU Energy, No. EO97070459, February 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Oral direct testimony before the State of New York on behalf of Niagara Mohawk Corporation in *Philadelphia Corporation, et al., v. Niagara Mohawk*, No. 71149, November 1996, regarding interpretation of low-head hydro IPP contract quantity limits.

Oral direct testimony before the State of New York on behalf of Niagara Mohawk Corporation in *Black River Limited Partnership v. Niagara Mohawk Power Corporation*, No. 94-1125, July 1996, regarding interpretation of IPP contract language specifying estimated energy and capacity purchase quantities.

Oral direct testimony on behalf of *Eastern Utilities Associates* before the Massachusetts Department of Public Utilities, No. 96-100 and 2320, July 1996, regarding issues in restructuring of Massachusetts electric industry for retail access.

Affidavit before the Kentucky Public Service Commission on behalf of *Big Rivers Electric Corporation* in PSC Case No. 94-032, June 1995, regarding modifications to an environmental surcharge mechanism.

Rebuttal testimony on behalf of utility in *Eastern Energy Corporation v. Commonwealth Electric Company*, American Arbitration Association, No. 11 Y 198 00352 04, March 1995, regarding lack of net benefits expected from a terminated independent power project.

Direct testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Power & Light Company in *Pennsylvania Public Utility Commission et al. v. UGI Utilities, Inc.*, Docket No. R-932927, March 1994, regarding inadequacies in the design and pricing of UGI's proposed unbundling of gas transportation services.

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of Interstate Energy Company, *Application of Interstate Energy Company for Approval to Offer Services in the Transportation of Natural Gas*, Docket No. A-140200, October 1993, and rebuttal testimony, March 1994.

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Oral rebuttal testimony before the American Arbitration Association, on behalf of Babcock and Wilcox, File No. 53-199-00127-92, May 1993, regarding the economics of an incentive clause in a cogeneration operations and maintenance contract.

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August 31, 2011

EXHIBIT _____

KPSC Case No. 2011-00401
KIUC First Set of Data Requests
Dated January 13, 2012
Item No. 28
Page 1 of 1

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that support, source, and/or otherwise address the assumptions used in the analyses presented by Mr. Weaver in his Direct Testimony. This includes, but is not limited to, any alternative assumptions that were considered but not used in the analyses.

RESPONSE

Please see KPSC 1-48 and the attachments to this response. Confidential protection is being sought for attachments 2 and 3.

WITNESS: Scott C Weaver

SC EXHIBIT 19

SC EXHIBIT 20

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

And

In the Confidential File Materials at the PSC

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-2, page 2. CO2 prices.

a. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "base" fleet assumption for CO2 prices from 2022 through 2040.

b. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "FT-CSAPR: Higher Band" assumption for CO2 prices from 2022 through 2040.

RESPONSE

a. & b. The "base (FT-CSAPR)" carbon dioxide price (CO2) and the "FT-CSAPR: Higher Band" CO2 price reflect a national carbon tax and an industry consensus view. The price is escalated by the forecasted Consumer Price Index. The final price is benchmarked to proprietary third-party estimates.

A consensus view represents the amalgamation of various sources of information. The long-term forecast is shaped by the views of many stakeholders, including, but not limited to:

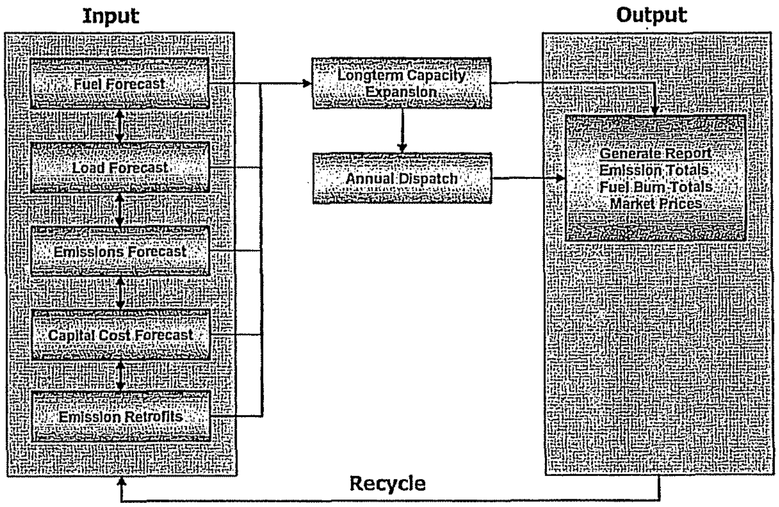
Investment Community - Equity and Fixed Income analysts
Third-Party Consultants - IHS Cera, PIRA, Wood Mackenzie
Industry Groups - Edison Electric Institute
Government Agencies - EPA, DOE, NERC, FERC
Trade Press - Argus Air Daily, Coal Daily, Coal Weekly, The Energy Daily, Megawatt Daily, Gas Daily
Various Stakeholders - Independent System Operators, Interest Groups (Environmental and Industry)
Energy Companies - Listen to earnings calls, press releases, SEC filings, etc
Internal Information - Experience from other organizations within the company.
Independent Studies - Proprietary research studies

The company uses this information to develop and test the robustness of the long-term forecast. In the case of opposing views, we use the contrary position to better understand the reasons that support our view. At times, we have differing views from other stakeholders.

The long-term forecast represents a fundamental view of the primary drivers to the energy market. Each primary driver (supply, demand, fuel, policy, etc) is developed by company experts and reflects public and non-public information. These industry views represent a sustainable outlook over the forecast period.

A third-party dispatch model, AuroraXMP, uses the industry views to create a series of long-term industry projections: electricity price, fuel consumption, new build, retirements, etc. Figure 1: illustrates the forecast process.

Figure 1: AuroraXMP Forecast Process

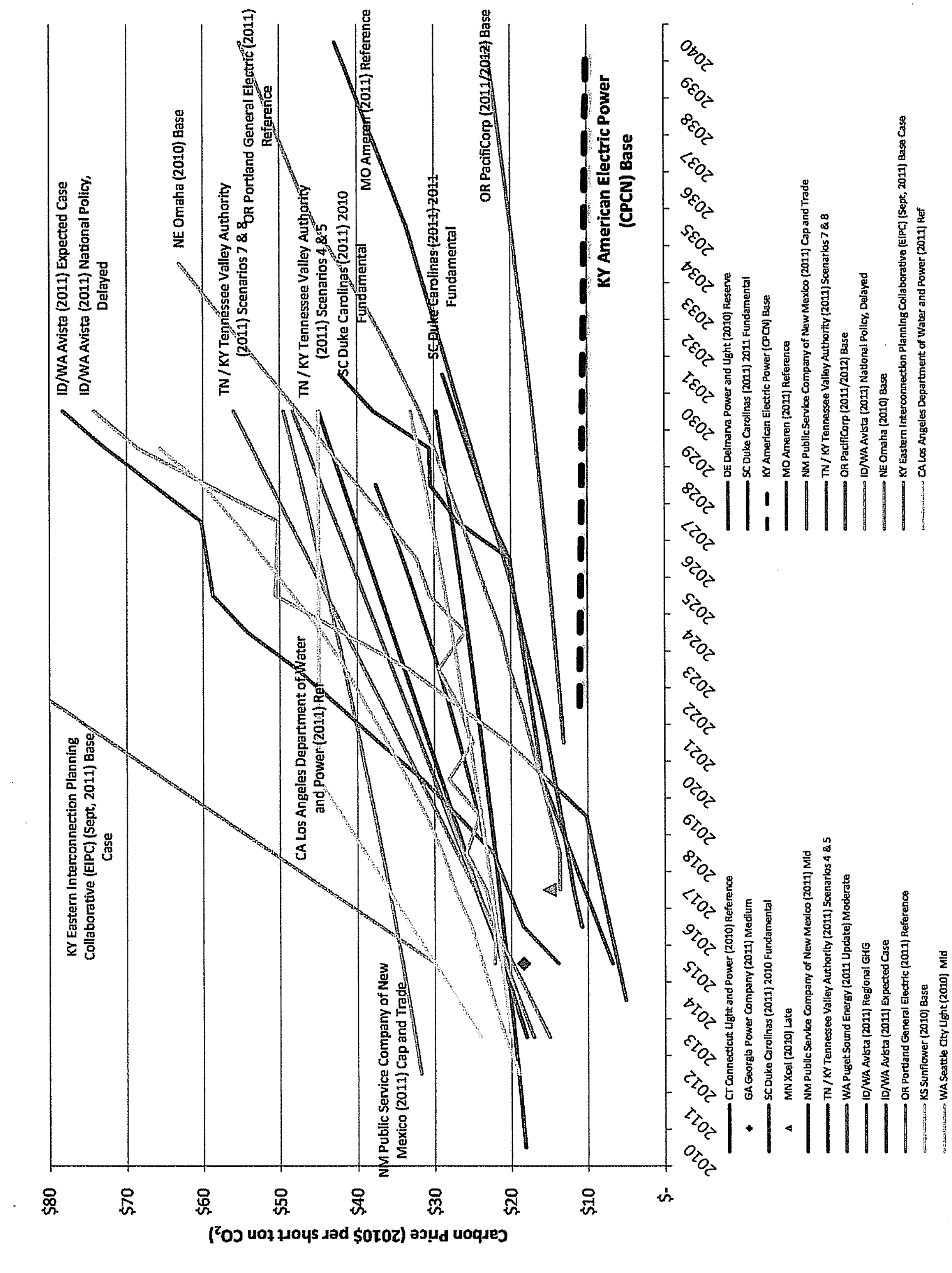


After each forecast, company experts review the results for robustness and iterate until the market reaches equilibrium. The final outlook is benchmarked to the consensus view.

WITNESS: Scott C Weaver, Karl R. Bletzacker

EXHIBIT _____

Exhibit____JIF-7B



Reference case CO2 prices from other US utilities

SC EXHIBIT 22

EXHIBIT ______

STATE OF SOUTH CAROLINA	**BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**
(Caption of Case) IN RE:	
Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (IRP)	**COVER SHEET**
	DOCKET NUMBER: 2011 - 10 - E

(Please type or print)

Submitted by:	Charles A. Castle	**SC Bar Number:**	79895
Address:	Duke Energy	**Telephone:**	704.382.4499
	550 S Tryon St., DEC45A	**Fax:**	
	Charlotte, NC 28202	**Other:**	
		Email:	alex.castle@duke-energy.com

NOTE: The cover sheet and information contained herein neither replaces nor supplements the filing and service of pleadings or other papers as required by law. This form is required for use by the Public Service Commission of South Carolina for the purpose of docketing and must be filled out completely.

DOCKETING INFORMATION (Check all that apply)

☐ **Emergency Relief demanded in petition** ☐ **Request for item to be placed on Commission's Agenda expeditiously**

☒ **Other: Duke Energy Carolinas' 2011 Integrated Resource Plan and Motion for Confidential Treatment**

INDUSTRY (Check one)	NATURE OF ACTION (Check all that apply)		
☒ Electric	☐ Affidavit	☐ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certification
☐ Electric/Telecommunications	☐ Answer	☒ Motion	☐ Request for Investigation
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☒ Other: 2011 Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

SC EXHIBIT 23

Duke Energy®
Carolinas

Charles A. Castle
Senior Counsel

Duke Energy Carolinas, LLC
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Charlotte, NC 28202

Tel 704.382.4499
Fax 980.373.8534
alex.castle@duke-energy.com

September 1, 2011

VIA ELECTRONIC FILING AND
HAND DELIVERED CONFIDENTIAL VERSION

Ms. Jocelyn Boyd
Chief Clerk of the Commission
Public Service Commission of South Carolina
Synergy Business Park, Saluda Building
101 Executive Center Drive
Columbia, SC 29210

Re: Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan
Motion for Confidential Treatment
Docket No. 2011-10-E

Dear Ms. Boyd:

Enclosed for filing please find the CONFIDENTIAL VERSION of Duke Energy Carolinas, LLC's ("Duke Energy Carolinas" or "the Company") 2011 Integrated Resource Plan ("2011 IRP"). The Company respectfully requests that it be permitted to file the CONFIDENTIAL VERSION under seal and maintained as confidential pursuant to Order No. 2005-226, "ORDER REQUIRING DESIGNATION OF CONFIDENTIAL MATERIALS."

The 2010 IRP contains certain confidential information (portions of the tables in Appendix C (pages 139-141) and the tables in Appendix I (page 165)). The information contained therein is proprietary and commercially sensitive, and, if disclosed, could adversely affect the Company's ability to provide least cost resources for its customers. In addition, Appendix F of the 2011 IRP contains Duke Energy Carolinas' most recently-filed FERC Form 715. As FERC Form 715 contains critical energy infrastructure information that should be kept confidential and non-public, Duke Energy Carolinas is also filing it under seal and requests that the Commission treat this information as confidential and protect it from public disclosure.

Thus, Duke Energy Carolinas respectfully requests that the Commission grant its request for confidential treatment pursuant to 26 S.C. Code Ann. Regs. 103-804(S)(2)(Supp. 2010). A copy of the Public version of the 2011 IRP is being filed electronically and a copy of the CONFIDENTIAL VERSION of the 2011 IRP is being hand delivered to the Commission and the Office of Regulatory Staff under seal.

Please consider this correspondence as Duke Energy Carolinas' Motion for Confidential Treatment of the above-referenced information in Appendices C, F and I of the 2011 IRP.

Thank you for your consideration of this matter and please contact me with any questions.

Very truly yours,

Charles A. Castle

Enclosures
cc: Shannon Bowyer Hudson, Esq.

The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2011

TABLE OF CONTENTS

Integrated Resource Plan – abbreviations

Carbon Dioxide	CO_2
Central Electric Power Cooperative, Inc.	CEPCI
Certificate of Public Convenience and Necessity	CPCN
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Coal Combustion Residuals	CCR
Combined Construction and Operating License	COL
Combined Cycle	CC
Combustion Turbines	CTs
Commercial Operation Date	COD
Compact Fluorescent Light bulbs	CFL
Cross State Air Pollution Rule	CSAPR
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Eastern Interconnection Planning Collaborative	EIPC
Electric Membership Corporation	EMC
Electric Power Research Institute	EPRI
Energy Efficiency	EE
Environmental Protection Agency	EPA
Federal Energy Regulatory Commission	FERC
Federal Loan Guarantee	FLG
Flue Gas Desulphurization	FGD
General Electric	GE
Greenhouse Gas	GHG
Heating, Ventilation and Air Conditioning	HVAC
Information Collection Request	ICR
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Interruptible Service	IS
Load, Capacity, and Reserve Margin Table	LCR Table
Maximum Achievable Control Technology	MACT
Nantahala Power & Light	NP&L
National Ambient Air Quality Standards	NAAQS
National Pollutant Discharge Elimination System	NPDES
NC Department of Environment and Natural Resources	NCDENR
NC Green Power	NCGP
New Source Performance Standard	NSPS
Nitrogen Oxide	NO_x
North American Electric Reliability Corp	NERC
North Carolina	NC
North Carolina Clean Smokestacks Act	NCCSA
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1

Integrated Resource Plan – abbreviations

North Carolina Utilities Commission	NCUC
Notice of Proposed Rulemaking	NOPR
Nuclear Regulatory Commission	NRC
Palmetto Clean Energy	PaCE
Parts Per Billion	PPB
Photovoltaic	PV
Piedmont Municipal Power Agency	PMPA
Plug-In Electric Vehicles	PEV
Power Delivery	PD
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Public Service Commission of South Carolina	PSC
Purchase Power Agreement	PPA
Qualifying Facility	QF
Rate Impact Measure	RIM
Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Energy Certificates	REC
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Resource Conservation Recovery Act	RCRA
Saluda River Electric Cooperative	SR
Selective Catalytic Reduction	SCR
SERC Reliability Corporation	SERC
South Carolina	SC
Southeastern Power Administration	SEPA
Standby Generation	SG
State Implementation Plan	SIP
Sulfur Dioxide	SO_2
Technology Assessment Guide	TAG
Total Resource Cost	TRC
United States Department of Energy	USDOE
Utility Cost Test	UCT
Virginia/Carolinas	VACAR
Volt Ampere Reactive	VAR
Western Carolina University	WCU

FORWARD

This Integrated Resource Plan (IRP) is Duke Energy Carolinas' biennial report under the revised North Carolina Utilities Commission (NCUC) Rule R8-60. A cross reference identifying where each regulatory requirement can be found within this IRP is provided in Appendix K.

NCUC Rule R8-60 subparagraph (h) (2) requires by September 1 of each year in which a biennial report is not required to be filed, an annual report to be filed with the NCUC containing an updated 15-year forecast of the items described in R8-60 subparagraph (c) (1), as well as significant amendments or revision to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable. The following updates to the 2010 IRP are provided in the Duke Energy Carolinas 2011 IRP Annual Report.

a) 15-year forecast
b) Short term action plan
c) Existing Generation Plants in Service
d) Renewable Energy Initiatives
e) Energy Efficiency and Demand Side Management peak and energy impacts
f) Wholesale Power Sales Commitments
g) Legislative and Regulatory Issues
h) Fundamental fuel, energy, and emission allowance prices
i) Generating units projected to be retired
j) Load and Resource Balance
k) Changes to existing and future resources
l) Overall planning process conclusions incorporating a) through l) above
m) Detailed information pertaining to the requirement that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan) as a stipulation to the North Carolina Department of Air Quality (NCDAQ) Air Permit for Cliffside Unit 6. This information can be found in Appendix J.

1. EXECUTIVE SUMMARY

Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company), a subsidiary of Duke Energy Corporation, utilizes an integrated resource planning approach to ensure that it can reliably and economically meet the electric energy needs of its customers well into the future. Duke Energy Carolinas considers a diverse range of resources including renewable, nuclear, coal, gas, energy efficiency (EE), and demand-side management (DSM)[1] resources. The end result is the Company's IRP.

Consistent with its responsibility to meet customer energy needs in a way that is affordable, reliable, and clean, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs, and other variables. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, the emergence and development of new technologies, and regional economic development considerations are also important factors to consider as long-term decisions are made regarding new resources.

Company management uses all of these qualitative perspectives in conjunction with its quantitative analyses to ensure that Duke Energy Carolinas will meet near-term and long-term customer needs, while maintaining the operational flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. As a result, the Company's plan is designed to be robust under many possible future scenarios.

The notable changes from the 2010 IRP to the 2011 IRP are the projected increase in peak generation need in 2015 due to increased load projections, updated assumptions regarding the energy impacts of Compact Fluorescent Lights (CFLs) and lower projected capacity impacts from Demand Side Management programs, as well as changes in the projected compliance portfolio relating to the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). The overall impact of these factors results in a resource need of 790 MWs in 2015.

The increased load projection is driven primarily by an increase in the projected demand from the industrial sector. The 2011 load forecast also incorporates a change in methodology related to the projected load impacts of CFLs in the residential and commercial sectors. These methodology changes included a change in the factors utilized for the residential sector and no incremental CFL impact, beyond what's reflected in the historical sales trends.

[1] Throughout this IRP, the term EE will denote conservation programs while the term DSM will denote Demand Response programs, consistent with the language of N.C. Gen. Stat. 62-133.8 and 133.9.

The lower projections of DSM impacts were driven primarily by the anticipated impact of the proposed Environmental Protection Agency (EPA) Reciprocating Internal Combustion Engine (RICE) rule, which limits hours of non-emergency operation of emergency generators located at commercial and industrial facilities. This rule, as proposed, is projected to significantly impact Duke Energy Carolinas' PowerShare program. The 2011 DSM projections were updated to reflect the manner in which the RICE rule will materially limit participation in the PowerShare program by our customers. The projected reduction in DSM impacts results in a corresponding increase in our customers' capacity needs.

Additionally, in the 2011 IRP, the analysis reflects a shift in the Company's strategy for NC REPS compliance over the long term. In the 2010 IRP, the long term NC REPS compliance strategy relied primarily on biomass resources during the first 10 years and then shifted to wind resources for the remainder of the planning period. Based upon recent proposals for wind purchased power agreements and the continuing federal regulatory uncertainty regarding treatment of biomass generation, for the 2011 IRP, the Company has adopted a strategy with increased reliance on wind resources during the first 10 years and a shift to biomass resources for the remainder of the planning period. This change in strategy impacts the 2015 peak resource requirement because only a small percentage of the rated capacity for wind resources can be counted toward meeting the Company's system peak, as opposed to the more reliable expected system peak contribution from biomass resources.

The 2011 IRP continues to reflect the retirement of Duke Energy Carolinas' older coal units without flue gas desulfurization (FGDs) facilities (also known as SO_2 scrubbers). These planned retirements are driven primary by the recently proposed EPA Mercury Utility Maximum Achievable Control Technology (MACT) rule. The MACT rule is expected to be finalized in November 2011, with required control technologies to be installed by January 1, 2015. Other emerging environmental regulations that also are expected to impact the retirement decisions relating to the Company's existing coal fleet include the Coal Combustion Residuals (CCR) rule, Cross State Air Pollution Rule (CSAPR), Sulfur Dioxide (SO_2) and Ozone National Ambient Air Quality standards (NAAQS). The Company has developed the 2011 IRP based on expectations of how these rules will be ultimately established.

Greenhouse gas (GHG) regulations or legislation also have the potential to impact the Company's resource plans. From 2007 to 2009, multiple GHG cap and trade bills were introduced in Congress. More recently, Clean Energy Standards (CES) have been discussed in lieu of cap and trade legislation or regulation. A CES would require that a certain percentage (e.g. 10% in 2015 escalating up to 30% in 2030) of a utility's retail sales be met with combined cycle (CC) natural gas, nuclear, EE, or renewable energy. At present, the Company does not anticipate that Congress will consider GHG legislation through the end of

2012. Beyond 2012, the prospects for possible enactment of any legislation mandating reductions in GHG emissions are highly uncertain. Although the Company continues to believe that Congress will eventually adopt some form of mandatory GHG emission reduction or Clean Energy legislation, the timing and form of any such legislation remains highly uncertain. In the absence of federal GHG or Clean Energy legislation, the EPA continues to pursue GHG regulations on new and existing units. EPA has announced its plans to issue a proposed regulation for fossil-fired generating units in 2011. The impacts of future EPA regulations are uncertain at this time; however the Company believes that it is prudent to continue to plan for a carbon-constrained future. To address this uncertainty, the Company has evaluated a range of CO_2 prices, in addition to potential Clean Energy legislation.

Planning Process Results

Duke Energy Carolinas' generation resource needs increase significantly over the 20-year planning horizon of the 2011 IRP. Cliffside Unit 6 and the Buck and Dan River natural gas CC units, along with the Company's EE and DSM programs, will fulfill these needs through 2014. Beginning in 2015, the Company has a capacity need of 790 MWs to meet its projected load requirements along with a 17% reserve margin. Even if the Company fully realizes its goals for EE and DSM, the resource need grows to approximately 7,030 MWs by 2031. This projected capacity need is higher than that reflected in the 2010 Duke Energy Carolinas IRP due primarily to higher load projections and the other reasons listed above.

The 2011 Duke Energy Carolinas IRP outlines the Company's options and plans for meeting the projected long-term needs. The factors that influence resource needs are:

- Future load growth projections;
- The amount of EE and DSM that can be achieved;
- Resources needed to meet the NC REPS requirement;
- Reductions in existing resources, for example, due to unit retirements and expiration of purchased power agreements (PPA); and
- Meeting the Company's 17% target planning reserve margin over the 20-year horizon.

A key purpose of the IRP is to provide the Company's management with information to aid in making the decisions necessary to ensure that Duke Energy Carolinas has a reliable, diverse, environmentally sound, and reasonably priced portfolio of resources over time.

In the short-term, the 2011 IRP analysis results indicate the need for peaking and intermediate resources as early as 2015 and 2016 and at various points throughout the study period. The results also show the need for new baseload facilities as early as 2018.

For Duke Energy Carolinas' longer term need, the Company's analysis continues to affirm the potential benefits of new greenhouse gas emission-free nuclear capacity in a carbon-constrained future. The Company's analysis considered a portfolio based on full ownership of the 2,234 MW Lee Nuclear Station in 2021 and 2023, as well as a portfolio that reflects regional nuclear generation equivalent to the MWs associated with Lee Nuclear Station spread over 2018 to 2028. The regional nuclear portfolio is illustrative of a potential regional nuclear portfolio and the Company developed this potential portfolio based on its recent activities to procure new nuclear generation and to sell a portion of the Lee Nuclear Station. Specifically, in February 2011, JEA (formerly Jacksonville Electric Authority), located in Jacksonville, Florida, signed an option to potentially purchase up to 20% of Lee Nuclear Station. In July 2011, the Company signed a letter of intent with Public Service Authority of South Carolina (Santee Cooper) to perform due diligence and potentially acquire an option for a minority interest (5 to 10% of the capacity of the two units) in Santee Cooper's 45 percent ownership of the planned new nuclear reactors at V.C. Summer (Summer) Nuclear Generating Station in South Carolina. The new Summer units are scheduled to be online between 2016 and 2019.

The results of the Company's analysis indicate that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2011 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Although the regional nuclear portfolio assumes 10% of the Summer station is purchased, the Company's decision on whether and how much to purchase will be based on many factors, including the results of the due diligence related to Summer, the capacity need at the time of the decision, and the financial implications of the purchase on the Company. Duke Energy Carolinas will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

Both DSM and EE programs play important roles in the Company's development of a balanced, cost-effective and environmentally responsible resource portfolio. Renewable generation options are also necessary to meet NC REPS enacted in 2007. These resources will be incorporated more broadly into the Company's resource portfolio to the extent they become more cost-effective in comparison with traditional supply-side resources and with consideration of other qualitative issues such as their intermittency and relative contribution to meeting peak capacity needs. Energy savings resulting from EE programs may also be used to meet, in part, the Company's REPS obligations. The Company's REPS Compliance Plan is being filed concurrently with the 2011 IRP, pursuant to the requirements of NCUC Rule R8-67.

The 2011 IRP also includes the Company's plan for meeting the requirements set forth in the Cliffside Unit 6 NCDAQ Air Permit (Cliffside Air Permit). The Cliffside Air Permit requires the Company take specific actions to render Cliffside Unit 6 carbon neutral by 2018. In the context of the 2011 IRP, the Company is seeking approval from the NCUC of the proposed plan as required by the Cliffside Air Permit.

In light of the Company's analyses, as well as the public policy debate relating to energy and environmental issues, Duke Energy Carolinas has developed a sustainable strategy to ensure that the Company can meet customers' energy needs reliably and economically over the near and long term. Duke Energy Carolinas' strategic action plan for long-term resources maintains prudent flexibility in the face of these dynamic circumstances.

The Company's Short Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, are summarized below:

- Take actions to ensure capacity needs beginning in 2015 are met. In addition to seeking to meet the Company's DSM and EE goals and meeting the Company's REPS requirements, actions to secure additional capacity may include purchased power or generating capacity or Company-owned generation. In addition, the Company's capacity needs will be evaluated in light of the combined needs and resources of Duke Energy Carolinas and Progress Energy Carolinas upon consummation of the merger between Duke Energy and Progress Energy, Inc. (Progress Energy).

- Continue to evaluate and plan for the retirement of older coal generation. Buck Steam Station Units 3 and 4 were retired in May 2011. Cliffside Units 1 through 4 and Dan River Units 1 and 2 are required to be retired in advance of the commercial operation of new generation at those locations. The timing of the retirements of the remaining un-scrubbed coal units in the 2015 timeframe will continue to be assessed as emerging federal environmental regulations are finalized over the coming years.

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of DSM and EE programs, and continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services. Approved and planned programs and pilots include:

- ➢ The Residential Retrofit program, which was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011 and in South Carolina in Docket 2010-51-E on February 24, 2010.

- ➢ The Home Energy Comparison Report pilot, which was approved by the Public Service Commission of South Carolina (PSC) in Docket 2010-50-E on March 24, 2010, and is currently only offered in South Carolina.

- ➢ The Smart Energy Now (SEN) pilot program, which was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011, and is currently only offered in North Carolina.

- ➢ Subject to approval by the NCUC and/or PSC, Duke Energy Carolinas plans to offer the following full program additions to its portfolio in the next year: Additional Smart $aver® Measures, Direct Install Low Income and Appliance Recycling.

- ➢ The Company is also considering a Home Energy Manager (HEM) Lite pilot program.

- Continue construction of the 825 MW Cliffside Unit 6, with the objective of bringing this additional capacity online by 2012 at the existing Cliffside Steam Station. As of June 2011, the project was over 80% complete.

- Continue construction of new combined-cycle natural gas generation at Buck and Dan River Steam Stations.

  - ➢ Buck CC Project: Continue construction of the 620 MW Buck CC project, with the objective of bringing this additional capacity on line by the end of 2011. As of July 2011, project was over 90% complete.

  - ➢ Dan River CC Project: Construction has begun on the 620 MW Dan River CC project is scheduled to be operational by the end of 2011. As of July 2011, the project was over 50% complete.

- Pursue the conversion of Lee Steam Station from coal to natural gas fuel. Lee Steam Station is reflected in the 2011 Duke Energy Carolinas IRP as a retired coal station in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts are ongoing.

- Continue to pursue the option for new nuclear generating capacity in the 2015 to 2025 timeframe.

  - ➢ The Company filed an application with the NRC for a COL in December 2007. The Company plans to continue to support the NRC evaluation of the COL.

  - ➢ The Company continues to pursue project development approvals and to evaluate the optimal time to file the Certificate of Environmental Compatibility and Public Convenience and Necessity (CPCN) in South Carolina, as well as other relevant regulatory approvals.

  - ➢ The Company will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.

  - ➢ The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

- Continue to evaluate market options for renewable generation and enter into contracts as appropriate. PPAs have been signed with developers of solar photovoltaic (PV), landfill gas, wind, and thermal resources. Additionally, renewable energy certificate (REC) purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with the Mercury MACT rule, the CCR rule, the CSAPR rule and the new Ozone NAAQS and SO_2.

- Continue to pursue existing and potential opportunities with wholesale power sales agreements within the Duke Energy Balancing Authority Area.

- Continue to monitor energy-related statutory and regulatory activities.

2. SYSTEM OVERVIEW, OBJECTIVES, AND PROCESS

A. SYSTEM OVERVIEW

Duke Energy Carolinas provides electric service to an approximately 24,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.41 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Tables 3.B and 3.C in Chapter 3.

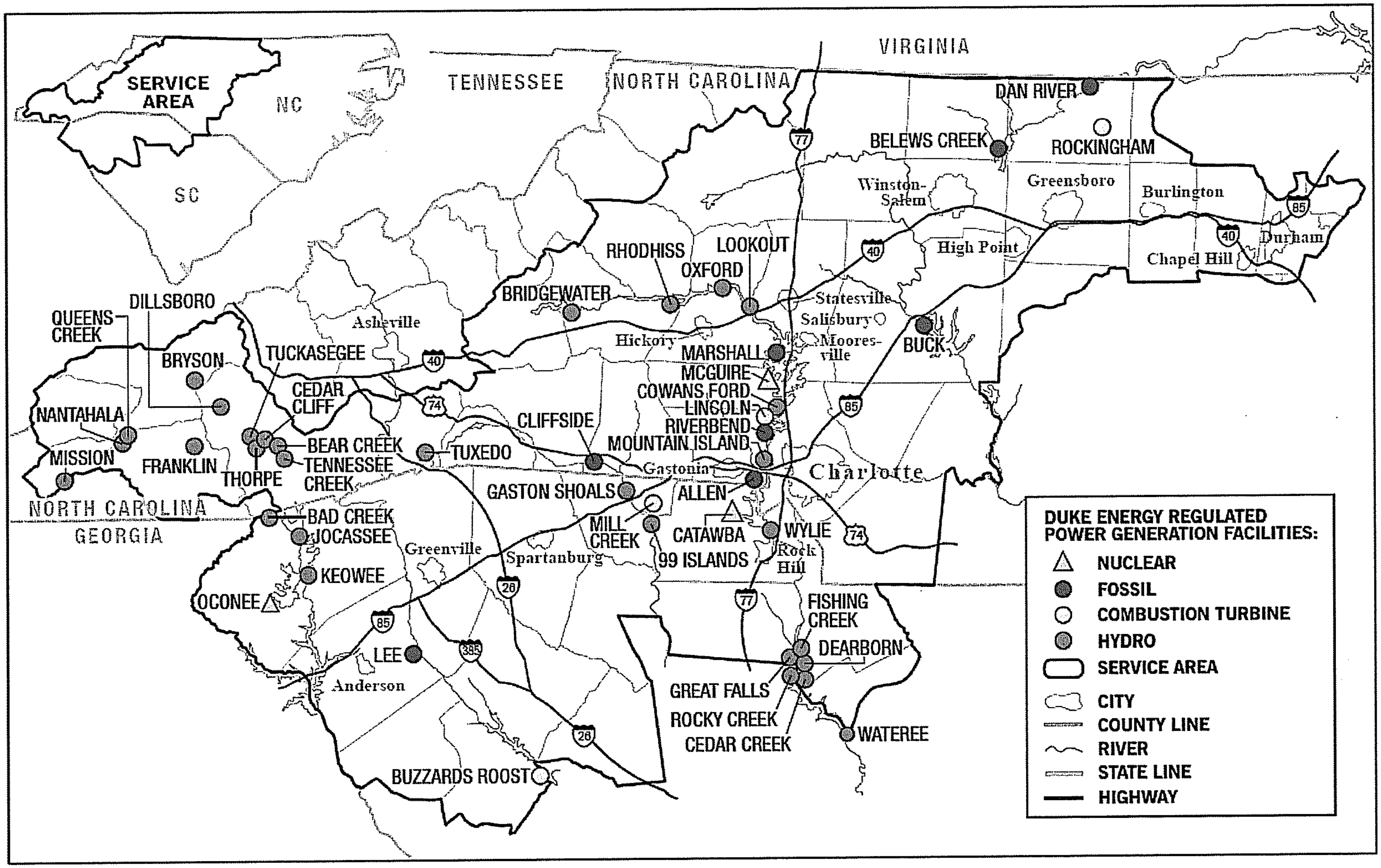
Duke Energy Carolinas currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station);
- Eight coal-fired stations with a combined capacity of 7,535 MW;
- 30 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,209 MW; and
- Eight combustion turbine stations with a combined capacity of 3,120 MW.

Duke Energy Carolinas' power delivery system consists of approximately 95,000 miles of distribution lines and 13,000 miles of transmission lines. The transmission system is directly connected to all of the utilities that surround the Duke Energy Carolinas service area. There are 35 circuits connecting with eight different utilities: Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas, and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the Duke Energy Carolinas system.

Duke Energy – Carolinas Power Generation Facilities



B. OBJECTIVES

Duke Energy Carolinas has an obligation to provide reliable and economic electric service to its customers in North Carolina and South Carolina. To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2011 IRP.

The purpose of this IRP is to outline a robust strategy to furnish electric energy services to Duke Energy Carolinas customers in a reliable, efficient, and economic manner while factoring in the uncertainty of the current environment.

The planning process itself must be dynamic and constantly adaptable to changing conditions. The IRP presented herein represents the most robust and economic outcome based upon the Company's analyses under various assumptions and sensitivities. Due to the uncertainty of the current environment including regulatory, economic, environmental and operating circumstances, Duke Energy Carolinas has performed sensitivity analysis as part of this IRP to account for these uncertainties. As the environment continues to evolve, Duke Energy Carolinas will continue to monitor and make adjustments as necessary and practical to reflect improved information and changing circumstances.

Duke Energy Carolinas' long-term planning objective is to employ a flexible planning process and pursue a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives. The major objectives of the plan presented in this filing are:

- Provide adequate, reliable, and economic service to customers in an uncertain environment.
- Maintain the flexibility and ability to alter the plan in the future as circumstances change.
- Choose a near-term plan that is robust over a wide variety of possible futures.
- Minimize risks with the development of a balanced portfolio.

C. PLANNING PROCESS

The development of the IRP is a multi-step process over the planning period of 2011-2031 involving these key planning functions:

- Develop planning objectives and assumptions.
- Consider the impacts of anticipated or pending regulations or events on existing resources (environmental, renewables, etc.).
- Consider two different regulatory constructs to assess the impact of potential CO_2 or Energy Policy legislation. The first included a CO_2 cap and trade construct with allowance prices beginning in 2016 projected at the lower end of pricing of previous proposed legislation. The second construct was based on Clean Energy Standard where an increasing percentage of retail sales starting in 2015 would come from energy efficiency, renewables, coal generation with carbon sequestration, nuclear and some allowance for combined cycle generation. Detailed descriptions of each of these constructs are available in Chapter 8.
- Prepare the electric load forecast. More details of this step may be found in Chapter 3.
- Identify EE and DSM options. More details concerning this step can be found in Chapter 4.
- Identify and economically screen for the cost-effectiveness of supply-side resource options. More details concerning this step of the process can be found in Chapter 5.
- Integrate the energy efficiency, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Perform detailed modeling of potential resource portfolios to determine the resource portfolio that exhibits the lowest cost (lowest net present value of costs) to customers over a wide range of alternative futures. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Evaluate the ability of the selected resource portfolio to minimize price and reliability risks to customers. More details concerning this step of the process can be found in Chapter 8 and Appendix A.

The analytical methodology includes the incorporation of sensitivity analysis of variables representing the highest risk going forward, such as the load forecast, construction costs, fuel prices, EE, carbon prices and emerging policy.

3. ELECTRIC LOAD FORECAST

The following section provides details on the Spring 2011 Load Forecast.

Duke Energy Carolinas retail sales have grown at an average annual rate of 0.9 percent from 1995 to 2010. The following table shows historical and projected major customer class growth, at a compound annual rate.

Table 3.A
Retail Load Growth (kWh sales)

Time Period	Total Retail	Residential	Commercial	Industrial Textile	Industrial Non-Textile
1995-2010	0.9%	2.7%	2.8%	-7.1%	-0.4%
1995-2005	1.2%	2.6%	3.4%	-6.0%	0.7%
2005-2010	0.4%	2.9%	1.7%	-9.4%	-2.6%
2010-2030	1.5%	1.5%	2.0%	-0.9%	1.1%

*Growth rates from 2010-2030 are derived using weather adjusted values for 2010. This differs from the Forecast Book located in Appendix B, which uses actual 2010 values.

A significant decline in the Industrial Textile class was the key contributor to the low load growth from 2005 to 2010, however, this decline was mostly offset by contributions in the Residential and Commercial classes over the same period. Over the last 5 years, an average of approximately 27,000 new residential customers per year has been added to the Duke Energy Carolinas service area.

Duke Energy Carolinas' total retail load growth over the planning horizon is driven by projected steady increases in the Residential, Commercial and Other Industrial classes. Textiles, however, are projected to experience a slow decline over the forecast horizon.

Retail load growth summaries are shown in the Duke Energy Carolinas Spring 2011 Forecast book in Appendix B.

The Residential load growth summaries shown in Table 3.A use the same history and forecast data for Residential Sales located on page 10 of the Forecast book in Appendix B. The Commercial load growth summaries use the same history and forecast data for Commercial Sales located on page 11 of the Forecast book in Appendix B. The Industrial

Textile load growth summaries use the same history and forecast data for Textile Sales located on page 13 of the Forecast book in Appendix B. The Industrial Non-Textile load growth summaries use the same history and forecast data for Other Industrial Sales located on page 14 of the Forecast book in Appendix B.

Table 3.B

Retail Customers (1000s, Annual Average)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential	1,814	1,840	1,872	1,901	1,935	1,972	2,016	2,052	2,059	2,072
Commercial	295	300	307	313	319	325	331	334	333	334
Industrial	8	8	8	8	7	7	7	7	7	7
Other	11	11	11	12	13	13	13	14	14	14
Total	2,128	2,159	2,198	2,234	2,275	2,317	2,368	2,407	2,413	2,427

Table 3.C

Electricity Sales (GWh Sold - Years Ended December 31)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential	23,272	24,466	23,947	25,150	26,108	25,816	27,459	27,335	27,273	30,049
Commercial	23,666	24,242	24,355	25,204	25,679	26,030	27,433	27,288	26,977	27,968
Industrial	26,902	26,259	24,764	25,209	25,495	24,535	23,948	22,634	19,204	20,618
Other	281	271	270	269	269	271	278	284	287	287
Total Retail	74,121	75,238	73,336	75,833	77,550	76,653	79,118	77,541	73,741	78,922
Wholesale	1,484	1,530	1,448	1,542	1,580	1,694	2,454	3,525	3,788	5,166
Total GWH	75,605	76,769	74,784	77,374	79,130	78,347	81,572	81,066	77,528	84,088

Note: Wholesale sales will vary over time due to new contract agreements.

Wholesale Power Sales Commitments

Table 3.D on the following page contains information concerning Duke Energy Carolinas' wholesale contracts.

Table 3.D

WHOLESALE CONTRACTS

Wholesale Customer	Contract Designation	Contract Term	Commitment (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NC/SC Munis		December 31,2018 with annual renewals. Can be terminated on one-year notice by either party after current contract term.	331	334	340	346	352	358	364	370	376	383
Concord, NC	Partial											
Dallas, NC	Partial											
Forest City, NC	Partial											
Kings Mountain, NC	Partial											
Lockhart Power	Partial											
Due West, SC	Partial											
Prosperity, SC	Partial											
Greenwood, SC	Full											
Highlands, NC	Full											
Western Carolina University	Full											
See Note 1												
New River EMC See Note 1	Full	December 31. 2021	35	35	36	37	37	38	39	40	41	42
Blue Ridge EMC See Note 1	Full	December 31, 2021	183	187	191	196	200	205	210	215	219	224
Piedmont EMC See Note 1	Full	December 31, 2021	90	91	92	93	94	95	97	98	99	100
Rutherford EMC See Note 1	Partial	December 31, 2021	159	164	193	197	211	215	219	223	227	231
Haywood EMC See Note 1	Full	December 31, 2021	26	26	26	27	27	28	28	29	29	29
Central See Note 1	Partial incr.to Full	January 1, 2013 - December 31, 2030	0	0	121	247	377	511	650	794	898	913
NCEMC See Note 2	Contract Backstand	Through Operating Life of Catawba and McGuire Nuclear Station	586	586	586	586	586	586	586	586	586	586
NCEMC	Capacity Sale	January 1, 2009 - December 31, 2038	72	72	72	72	72	72	72	72	72	72

Note 1: The analyses in the Annual Plan assumed that the contracts will be renewed or extended through the end of the planning horizon
Note 2: The annual commitment shown is the ownership share of Catawba Nuclear Station and is included in the load forecast.
Equivalent capacity is included as a portion of the Catawba Nuclear Station resource

The Spring 2011 Forecast includes projections of the energy needs of new and existing customers in Duke Energy Carolinas service territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy requirements from other suppliers. While this may reduce Duke Energy Carolinas obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that the contracts displayed in Table 3.D will be extended through the duration of the forecast horizon.

Pursuant to NCUC Rule R8-60(i)(1), a description of the methods, models and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models is provided on pages 4-6 of the Duke Energy Carolinas 2011 Forecast book located in Appendix B. Also, per NCUC Rule R8-60(i)(1)(A), a forecast of customers by each customer class and a forecast of energy sales (kWh) by each customer class is provided on pages 9-14 and pages 17-22 of the 2011 Forecast book located in Appendix B.

A tabulation of the utility's forecasts for a 20 year period, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of utility-sponsored energy efficiency programs are shown below in Tables 3.E and 3.F.

Load duration curves, with and without utility-sponsored energy efficiency programs, follow Tables 3.E and 3.F, and are shown as Charts 3.A and 3.B.

These values reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2011 to 2031.

The current 20-year forecast of the needs of the retail and wholesale customer classes, which does not include the impact of new energy efficiency programs, projects a compound annual growth rate of 1.8 percent in the summer peak demand, while winter peaks are forecasted to grow at 1.7 percent. The forecasted compound annual growth rate for energy is 1.9 percent.

If the impacts of new energy efficiency programs are included, the projected compound annual growth rate for the summer peak demand is 1.7 percent, while winter peaks are forecasted to grow at a rate of 1.6 percent. The forecasted compound annual growth rate for energy is 1.7 percent.

Table 3.E
Load Forecast without Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2011	17,596	17,121	91,750
2012	17,907	17,425	93,281
2013	18,353	17,869	95,307
2014	18,800	18,303	97,455
2015	19,273	18,746	100,044
2016	19,752	19,180	102,481
2017	20,220	19,665	104,929
2018	20,680	20,123	107,476
2019	21,122	20,539	109,865
2020	21,475	20,868	111,873
2021	21,826	21,128	113,859
2022	22,152	21,482	115,560
2023	22,469	21,782	117,366
2024	22,777	22,080	119,235
2025	23,120	22,379	121,087
2026	23,430	22,649	123,013
2027	23,777	22,922	124,979
2028	24,109	23,280	127,025
2029	24,419	23,584	129,081
2030	24,765	23,885	131,175
2031	25,121	24,186	133,281

Chart 3.A- Load Duration Curves without Energy Efficiency

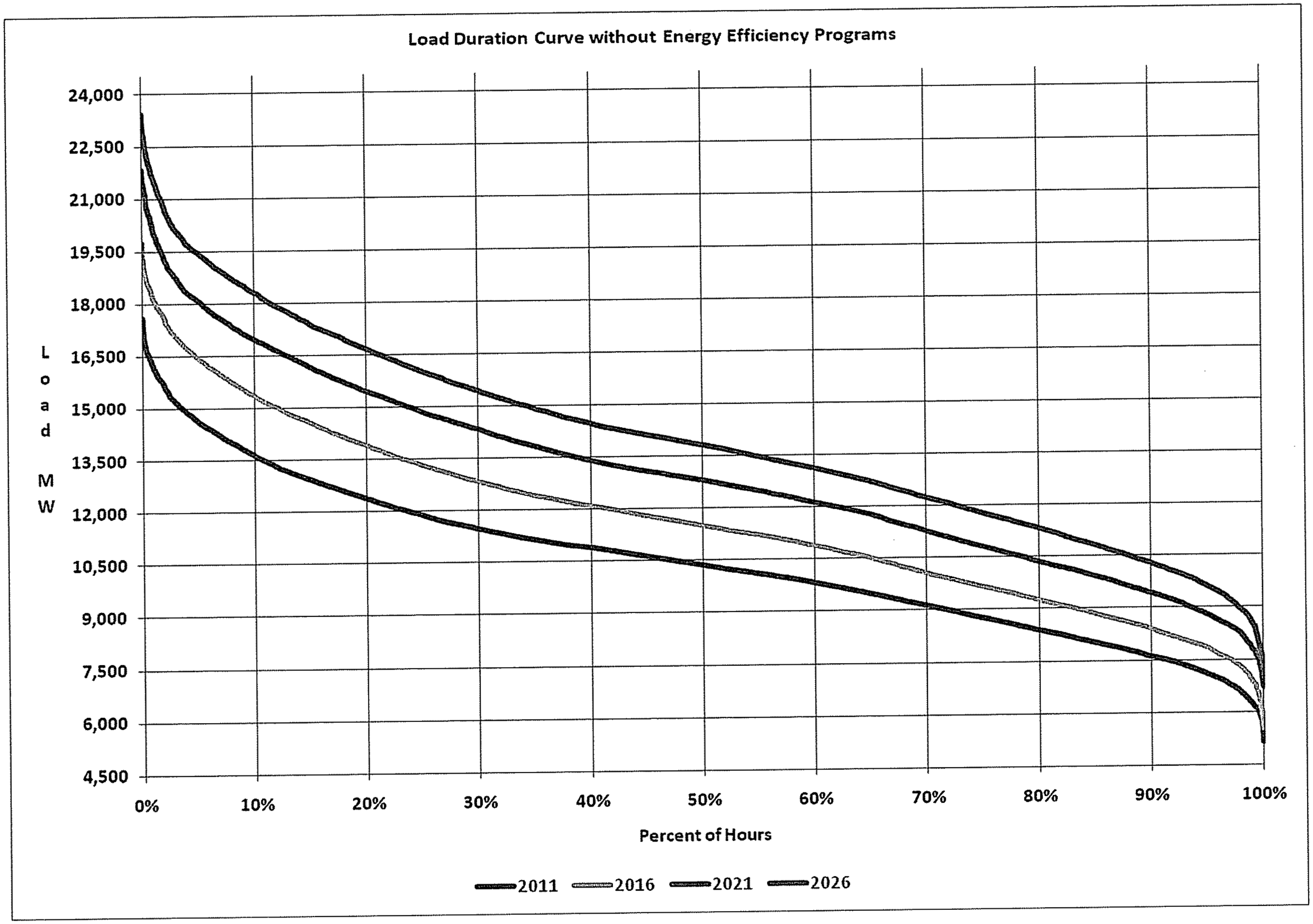
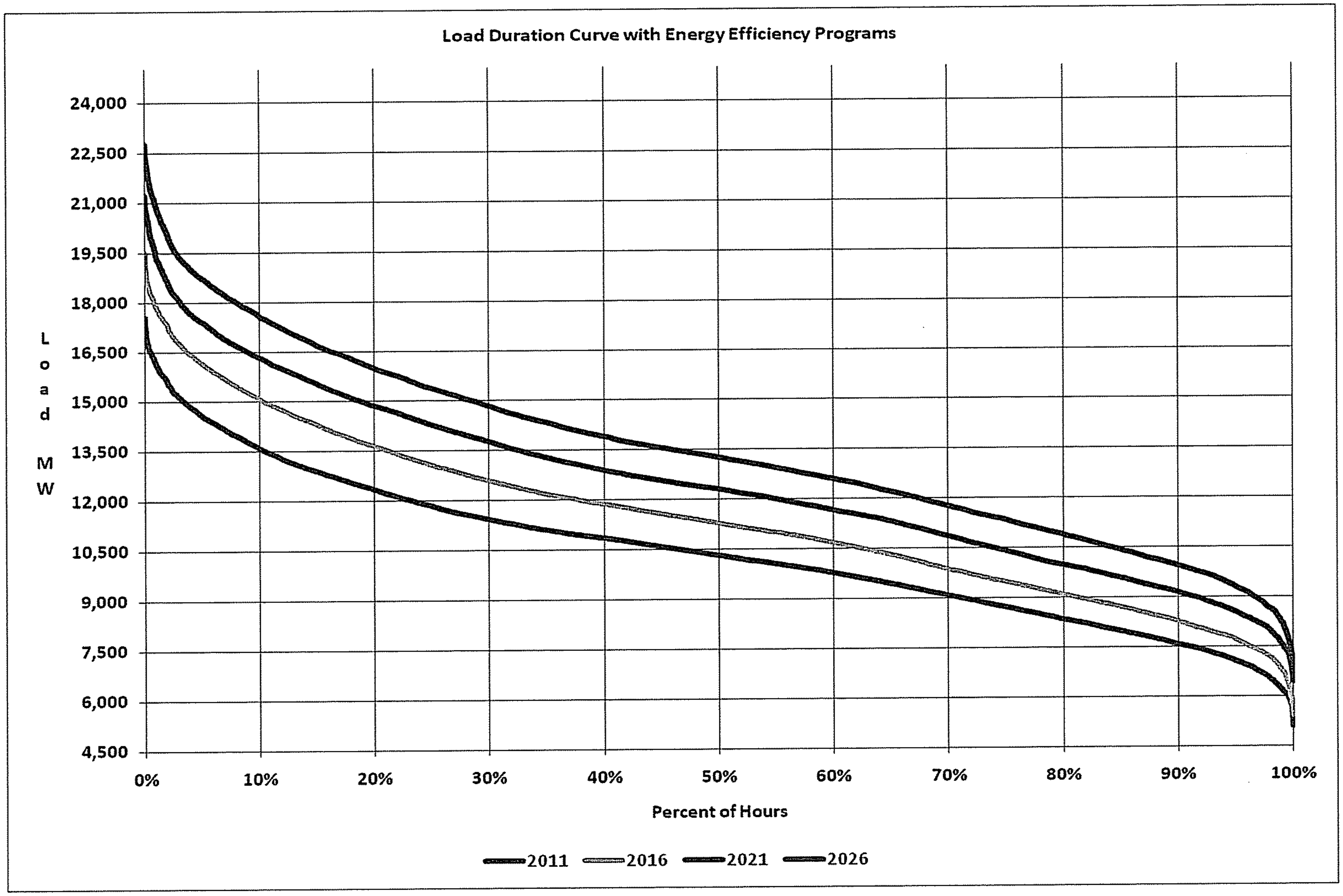


Table 3.F
Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2011	17,557	17,115	91,479
2012	17,812	17,359	92,679
2013	18,245	17,773	94,518
2014	18,680	18,177	96,507
2015	19,032	18,543	98,517
2016	19,476	18,891	100,472
2017	19,877	19,305	102,438
2018	20,265	19,694	104,503
2019	20,644	20,042	106,409
2020	20,901	20,304	107,936
2021	21,214	20,492	109,440
2022	21,530	20,835	111,063
2023	21,836	21,124	112,791
2024	22,135	21,412	114,580
2025	22,465	21,697	116,350
2026	22,733	21,956	118,193
2027	23,099	22,217	120,075
2028	23,420	22,565	122,035
2029	23,715	22,853	124,003
2030	24,050	23,142	126,008
2031	24,393	23,430	128,025

Chart 3.B - Load Duration Curves with Energy Efficiency



4. ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

In May 2007, Duke Energy Carolinas filed its application for approval of EE and DSM programs under its save-a-watt initiative. The Company received the final order for approval for these programs from the NCUC in July 2010 and from the PSC in May 2009.

Duke Energy Carolinas uses EE and DSM programs to help manage customer demand in an efficient, cost-effective manner. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption (conservation programs) and DSM programs that reduce energy demand (demand-side management or demand response programs and certain rate structure programs). The following are the current EE and DSM programs in place in the Carolinas:

Demand Response – Load Control Curtailment Programs

These programs can be dispatched by the utility and have the highest level of certainty. Once a customer agrees to participate in a demand response load control curtailment program, the Company controls the timing, frequency, and nature of the load response. Duke Energy Carolinas' current load control curtailment programs are:

- **Power Manager®** - Power Manager is a residential load control program. Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to cycle their central air conditioning systems and, additionally, to interrupt the central air conditioning when the Company has capacity needs.

Demand Response – Interruptible and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use curtailment programs include:

- **Interruptible Power Service (IS)** (North Carolina Only) - Participants agree contractually to reduce their electrical loads to specified levels upon request by Duke Energy Carolinas. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

- **Standby Generator Control (SG)** (North Carolina Only) - Participants agree contractually to transfer electrical loads from the Duke Energy Carolinas source to their standby generators upon request by Duke Energy Carolinas. The generators in this program do not operate in parallel with the Duke Energy Carolinas system and therefore, cannot "backfeed" (i.e., export power) into the Duke Energy Carolinas system. Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

- **PowerShare®** is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary), and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).
    - PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.
    - PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.
    - PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a Web site to view a posted energy price for that particular event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed.
    - PowerShare® CallOption: This DSM program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic

Events to 0, 5, 10 and 15 respectively.

- **Rates using price signals**

  - **Residential Time-of-Use (including a Residential Water Heating rate)**
    This category of rates for residential customers incorporates differential seasonal and time-of-day pricing that encourages customers to shift electricity usage from on-peak time periods to off-peak periods. In addition, there is a Residential Water Heating rate for off-peak water heating electricity use.

  - **General Service and Industrial Optional Time-of-Use rates**
    This category of rates for general service and industrial customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

  - **Hourly Pricing for Incremental Load**
    This category of rates for general service and industrial customers incorporates prices that reflect Duke Energy Carolinas' estimation of hourly marginal costs. In addition, a portion of the customer's bill is calculated under their embedded-cost rate. Customers on this rate can choose to modify their usage depending on hourly prices.

Energy Efficiency Programs
These programs are typically non-dispatchable, conservation-oriented education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All effects of these existing programs are reflected in the customer load forecast. Duke Energy Carolinas' existing conservation programs include:

- **Residential Energy Assessments**

  The Residential Energy Assessments program includes two separate measures: 1) Personalized Energy Report (PER) and 2) Home Energy House Call.

  The PER program is a residential energy efficiency program that provides single family home customers with a customized report about their home and family and how they use energy. In addition, the customer receives CFLs as an incentive to participate in the program.

The PER program requires customers to provide information about their home, number of occupants, equipment and energy usage and has two variations:

- A mailed offer where customers are asked to complete an included energy survey and mail it back to Duke Energy or complete the same survey online. Customers mailing the energy survey receive their PER in the mail and those completing it online receive their PER online as a printable PDF document.

- An online offer to our customers that have signed into our Online Services (OLS) bill pay and view environment. Online participants complete their energy survey online get their PER online as a printable PDF.

Home Energy House Call (HEHC) is a free in-home assessment designed to help our customers learn about home energy usage and how to save on monthly bills. The program provides personalized information unique to the customer's home and energy practices. An energy specialist visits the customer's home to analyze the total home energy usage and to pinpoint energy saving opportunities. An energy specialist will also explain how to improve the heating and cooling comfort levels, check for air leaks, examine insulation levels, review appliances, help the customer preserve the environment for the future and keep electric costs low. A customized report is prepared, explaining the steps the customer can take to increase efficiency. As a part of the Home Energy House Call program, customers receive an Energy Efficiency Starter Kit. At the request of the customer, the energy specialist can install the efficiency items to allow the customer to begin saving immediately.

- **Low Income Energy Efficiency and Weatherization Program**
  The purpose of this program is to assist low income residential customers with demand-side management measures to reduce energy usage through energy efficiency kits or through assistance in the cost of equipment or weatherization measures.

- **Energy Efficiency Education Program for Schools**
  The purpose of this program is to educate students about sources of energy and energy efficiency in homes and schools through a curriculum provided to public and private schools. This curriculum includes lesson plans, energy efficiency materials, and energy audits.

- **Residential Smart $aver® Energy Efficient Products Program**
  The Smart $aver® Program provides incentives to residential customers who

purchase energy-efficient equipment. The program has two components – CFLs and high-efficiency air conditioning equipment.

CFLs

The CFL program is designed to offer incentives to customers and increase energy efficiency by installing CFLs in high use fixtures in the home. The incentives have been offered in a variety of ways. The first deployment of this program distributed free coupons to be redeemed by the customer at a variety of retail stores. Later deployments used business reply cards and a web-based on-demand ordering tool where CFLs are shipped directly to the customer's home.

Heating Ventilation & Air Conditioning (HVAC) and Heat Pump

The residential air conditioning program provides incentives to customers, builders, and heating contractors (HVAC dealers) to promote the use of high-efficiency air conditioners and heat pumps. The program is designed to increase the efficiency of air conditioning systems in new homes and for replacements in existing homes.

- **Smart $aver® for Non-Residential Customers**

  The purpose of this program is to encourage the installation of high-efficiency equipment in new and existing non-residential establishments. The program provides incentive payments to offset a portion of the higher cost of energy-efficient equipment. The following types of equipment are eligible for incentives as part of the Prescriptive program: high-efficiency lighting, high-efficiency air conditioning equipment, high-efficiency motors, high-efficiency pumps, variable frequency drives, food services and process equipment. Customer incentives may be paid for other high-efficiency equipment as determined by the Company to be evaluated on a case-by-case basis through the Custom program.

The projected impacts from these programs are included in this year's assessment of generation needs.

Additional Programs Being Considered

In addition to our current portfolio of programs, Duke Energy Carolinas plans to add three additional concepts to our portfolio. These programs are similar to approved programs offered by Progress Energy Carolinas. The three additional programs are Additional Smart $aver® Measures, Direct Install Low Income and Appliance Recycle. A high-level overview is provided below.

- **Additional Smart $aver® Measures**

  Partnering with HVAC dealers, the program pays incentives to partially offset the cost of air conditioner and heat pump tune ups and duct sealing. This would be a new program and has not been offered in any of Duke Energy's jurisdictions. Projected impacts of this program were included in the analysis of generation needs.

- **Direct Install Low Income Program**
  Program that targets low income neighborhoods providing high impact direct install measures (CFLs, pipe and water heater wrap, low flow aerators and showerheads, HVAC filters and air infiltration sealing) and energy efficiency education. Projected impacts of this program were included in the analysis of generation needs.

- **Appliance Recycling Program**
  This is a program to incentivize households to turn in old inefficient refrigerators and freezers. Projected impacts of this program were not included in the analysis of generation needs due to the timing of approval of this concept.

The following pilot programs have been approved:

- **Residential Retrofit**
  This program was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011 and in South Carolina in Docket 2010-51-E on February 24, 2010. The Residential Retrofit program is designed to assist residential customers in assessing their energy usage, to provide recommendations for more efficient use of energy in their homes and to encourage the installation of energy efficient improvements by offsetting a portion of the cost of implementing the recommendations from the assessment. Projected impacts of this pilot program were included in the analysis of generation needs.

- **Home Energy Comparison Report**
  This pilot was approved by the Public Service Commission of South Carolina in Docket 2010-50-E on March 24, 2010 and will test the energy savings impact of providing periodic reports to targeted customers showing how their energy consumption compares to that of similar neighbors. This pilot program is currently only offered in South Carolina. Projected impacts of this pilot program were included in the analysis of generation needs.

- **Smart Energy Now (SEN)**
  The SEN pilot program was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011 and is designed to reduce energy consumption within the

commercial office space located in Charlotte City Center through community engagement leading to behavioral modification. In order to enable building managers and occupants to effectively make these behavioral modifications, they will be provided with additional energy consumption information and actionable efficiency recommendations. Projected impacts of this pilot were not included in the analysis of generation needs due to the timing of approval.

The following pilot program is being proposed:

- **Home Energy Manager (HEM) Lite**
  HEM Lite is a residential energy management solution designed for home owners with broadband internet service. The product offers energy efficiency and demand response benefits through a Wi-Fi enabled thermostat that will manage a customer's air conditioning system by providing schedules, modes (such as home/away/vacation), energy savings tips, messages, and alerts. The customer will have the tools to access and control their thermostat through any web browser or by downloading an "app" on their smart phone. In addition, it will provide customers with the opportunity to participate in demand response events. Overall, this product will provide simple, intuitive, and effective tools that will enable the customer to reduce and manage their overall energy usage.

Future EE and DSM programs

In addition to the programs and pilots listed above, Duke Energy Carolinas is actively working to add new programs to our portfolio that have not yet been developed. Estimates of the impacts of these yet-to-be-developed programs have been included in this analysis of generation needs.

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of DSM and EE programs and measures. DSMore is a financial analysis tool designed to estimate the value of DSM and EE measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing DSM and EE measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to incurred utility costs to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any state, federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas has made a strong commitment to EE and DSM. The Company recognizes EE and DSM as a reliable, valuable resource that is an option in the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. These EE and DSM programs help customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM to provide customers with universal access to these services and new technology. Duke Energy Carolinas has the expertise, infrastructure, and customer relationships to produce results and make it a significant part of its resource mix. Duke Energy Carolinas accepts the challenge to develop, implement, adjust as needed, and verify the results of innovative EE programs for the benefit of its customers.

The Duke Energy Carolinas' approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in energy efficiency and demand side programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment. For the period between the deployment of the Company's save-a-watt portfolio in 2009 and 12/31/2010, Duke Energy's conservation and demand response programs have reduced overall demand, including line losses, by approximately 500,000 net MWh and the Summer Peak has been reduced by over 700 MW. However, pursuing EE and DSM initiatives will not meet all our growing demands for electricity. The Company still envisions the need to secure additional nuclear and gas generation as well as cost-effective renewable generation, but the EE and DSM programs offered by Duke Energy Carolinas could address approximately half of the 2015 new resource need, if such programs perform as expected.

Table 4.A provides the base case projected load impacts of the EE and DSM programs through 2031. These load impacts were included in the base case IRP analysis. The Company assumes total EE savings will continue to grow on an annual basis through 2035, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. The projected load impacts from the DSM programs are based upon the Company's continuing, as well as the new, demand response programs. These projections have decreased from last year in part due to incorporation of impacts from the EPA's RICE rule. This EPA rule restricts the use of customer-sited generators to a very low level for demand response purposes. EPA is currently collecting comments on this rule so it is uncertain at this time if the rule will change and what the eventual impact will be on the Company's demand response programs. Duke Energy Carolinas is considering alternatives to address the reduction in DSM capability available.

Table 4.B provides a high case load impact scenario from the Company's EE and DSM programs. For EE programs, this scenario uses the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts

at 1% of retail sales every year after that until 2030, beyond which point the increase in the load impacts are adjusted to match the projected growth in retail sales. For DSM programs, the load impacts are increased to match the increase between base case and high case MWH retail sales for the appropriate customer class.

Table 4.C incorporates December 31, 2010 participation levels for all demand response programs and the capability of these programs projected for the summer of 2011.

Table 4.A Load Impacts of EE and DSM Programs – Base Case

Conservation and Demand Side Management Programs

	Conservation		Demand Response Peak MW					Total
			Summer Peak MW					Summer Peak
Year	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2011	271,026	39	145	48	331	249	775	814
2012	601,792	80	135	46	367	294	842	922
2013	788,832	102	128	19	364	343	854	955
2014	947,489	120	122	18	391	393	923	1,044
2015	1,526,825	208	116	17	414	436	983	1,190
2016	2,008,940	276	110	16	429	432	987	1,262
2017	2,491,055	343	110	16	429	432	986	1,329
2018	2,973,170	410	110	16	429	432	986	1,396
2019	3,455,286	478	110	16	429	432	986	1,465
2020	3,937,401	544	110	16	429	432	986	1,530
2021	4,419,513	611	110	16	429	432	986	1,598
2022	4,496,857	622	110	16	429	432	986	1,608
2023	4,575,552	633	110	16	429	432	986	1,619
2024	4,655,623	642	110	16	429	432	986	1,629
2025	4,737,095	655	110	16	429	432	986	1,642
2026	4,819,996	667	110	16	429	432	986	1,653
2027	4,904,346	679	110	16	429	432	986	1,665
2028	4,990,171	688	110	16	429	432	986	1,675
2029	5,077,501	703	110	16	429	432	986	1,689
2030	5,166,356	715	110	16	429	432	986	1,701
2031	5,256,768	727	110	16	429	432	986	1,714

Table 4.B Load Impacts of EE and DSM Programs – High Case

Conservation and Demand Side Management Programs

	Conservation		Demand Response Peak MW Summer Peak MW					Total Summer Peak
Year	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2011	271,026	39	163	54	373	264	855	894
2012	601,792	80	154	53	419	311	936	1,016
2013	788,832	102	147	21	418	362	947	1,049
2014	947,489	120	140	20	450	415	1,024	1,145
2015	2,070,090	283	134	19	478	460	1,091	1,374
2016	2,809,117	387	128	18	497	456	1,100	1,487
2017	3,548,145	490	128	18	500	457	1,104	1,594
2018	4,287,171	593	129	18	502	458	1,107	1,701
2019	5,026,201	698	129	19	503	460	1,111	1,809
2020	5,765,231	798	130	19	505	462	1,115	1,913
2021	6,504,259	902	130	19	507	463	1,118	2,020
2022	7,243,284	1,004	130	19	508	465	1,122	2,126
2023	7,982,312	1,107	131	19	510	467	1,126	2,233
2024	8,721,341	1,207	131	19	511	470	1,131	2,338
2025	9,460,367	1,313	132	19	513	472	1,136	2,448
2026	10,199,395	1,416	132	19	515	475	1,140	2,556
2027	10,938,425	1,519	132	19	516	477	1,145	2,663
2028	11,677,451	1,617	133	19	518	480	1,150	2,766
2029	12,416,478	1,724	133	19	520	483	1,155	2,879
2030	13,155,507	1,827	134	19	521	486	1,160	2,987
2031	13,385,729	1,859	134	19	523	489	1,165	3,024

Table 4.C

DSM Program Participation and Capability

DSM Program Name	Participation as of 12/31/10	2011 Estimated Summer IRP Capability (MW)
IS	69	145
SG	98	48
PowerShare Mandatory	115	313
PowerShare Generator	4	18
PowerShare Voluntary	4	N/A
PowerShare CallOption		
Level 0/5	-	-
Level 5/5	-	-
Level 10/5	-	-
Level 15/5	1	0
Power Manager	198,503	249
Total	198,794	775

Programs Evaluated but Rejected

Duke Energy Carolinas has not rejected any programs as a result of its EE and DSM program screening.

Looking to the Future

DSM Implementation Effectiveness – Duke Energy Carolinas has begun a review of the effectiveness of its DSM programs to reduce peak demand during reliability events. The goal of this review will be to gain insight on DSM parameters, such as duration of events and number of events and how these parameters impact the load reduction captured during a reliability event.

Grid Modernization – Duke Energy is pursuing implementation of grid modernization throughout the enterprise. The recent $200 million grant awarded to Duke Energy from the US DOE helps further that goal. Grid modernization is a mechanism to further enable adoption and market penetration of EE, DSM and plug-in electric vehicles (PEVs). In order to meet and support EE and DSM goals, the NCUC proposed a requirement to include grid modernization impacts in the IRP for North Carolina electric utilities (including Duke Energy Carolinas) in Docket E-100, Sub 126. Duke Energy Carolinas filed joint comments along with Dominion-North Carolina Power on February 26, 2010, in which the two utilities supported the inclusion of the impact of grid modernization as part of the IRP. The two utilities also advocated that grid modernization should be treated similarly to how EE and DSM resources are incorporated into the IRP. Progress Energy later joined Duke Energy Carolinas and Dominion-North Carolina Power in reply comments filed before the NCUC on March 26, 2010, further emphasizing these points.

5. SUPPLY-SIDE RESOURCES

A. EXISTING GENERATION PLANTS IN SERVICE

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2010, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 51.2% and 46.7%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, CT generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

Existing Resources

The tables below list the Duke Energy Carolinas plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Table 5.A

North Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	2	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	3	261.0	270.0	Belmont, N.C.	Conventional Coal
Allen	4	276.0	282.0	Belmont, N.C.	Conventional Coal
Allen	5	266.0	275.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1127.0**	**1161.0**		
Belews Creek	1	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2220.0**	**2270.0**		
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**256.0**	**262.0**		
Cliffside	1	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	2	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	3	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	4	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	5	556.0	562.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**754.0**	**764.0**		
Dan River	1	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	2	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	3	142.0	145.0	Eden, N.C.	Conventional Coal
Dan River Steam Station		**276.0**	**283.0**		
Marshall	1	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	2	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	3	658.0	658.0	Terrell, N.C.	Conventional Coal
Marshall	4	660.0	660.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		**2078.0**	**2078.0**		
Riverbend	4	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	5	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	6	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	7	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend Steam Station		**454.0**	**464.0**		
TOTAL N.C. CONVENTIONAL COAL		**7165.0 MW**	**7282.0 MW**		
Buck	7C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
Buck	8C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	12.0	15.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		**62.0**	**75.0**		
Dan River	4C	0.0	0.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	5C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	6C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		**48.0**	**62.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lincoln Station CTs		**1267.2**	**1488.0**		
Riverbend	8C	0.0	0.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	20.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend Station CTs		**64.0**	**90.0**		
Rockingham	1	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	2	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	3	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	4	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	5	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham CTs		**825.0**	**825.0**		
TOTAL N.C. COMB. TURBINE		**2266.2 MW**	**2540.0 MW**		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		**2200.0**	**2312.0**		
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	0	0	Morganton, N.C.	Hydro
Bridgewater Hydro Station		**11.5**	**11.5**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	2	0	0	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.48**	**0.48**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		**325.2**	**325.2**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		**27.9**	**27.9**		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro
Mountain Island	4	17	17	Mount Holly, N.C.	
Mountain Island Hydro Station		**62.0**	**62.0**		
Oxford	1	20.0	20.0	Conover, N.C.	Hydro
Oxford	2	20.0	20.0	Conover, N.C.	Hydro
Oxford Hydro Station		**40.0**	**40.0**		
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro
Rhodhiss	3	9.0	9.0	Rhodhiss, N.C.	Hydro
Rhodhiss Hydro Station		**30.0**	**30.0**		
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo Hydro Station		**6.4**	**6.4**		
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro
Bear Creek Hydro Station		**9.45**	**9.45**		
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro
Cedar Cliff Hydro Station		**6.4**	**6.4**		
Franklin	1	0	0	Franklin, N.C.	Hydro
Franklin	2	.6	.6	Franklin, N.C.	Hydro
Franklin Hydro Station		**.6**	**.6**		
Mission	1	0	0	Murphy, N.C.	Hydro
Mission	2	0	0	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**0.6**	**0.6**		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		**50.0**	**50.0**		
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		**9.8**	**9.8**		
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro
Thorpe Hydro Station		**19.7**	**19.7**		
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro
Tuckasegee Hydro Station		**2.5**	**2.5**		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Queens Creek Hydro Station		**1.44**	**1.44**		
TOTAL N.C. HYDRO		**603.97 MW**	**603.97 MW**		
TOTAL N.C. SOLAR		**8.43 MW**	**8.43 MW**	N.C.	Solar
TOTAL N.C. CAPABILITY		**12,243.60 MW**	**12,746.40 MW**		

Table 5.B

South Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lee	1	100.0	100.0	Pelzer, S.C.	Conventional Coal
Lee	2	100.0	102.0	Pelzer, S.C.	Conventional Coal
Lee	3	170.0	170.0	Pelzer, S.C.	Conventional Coal
Lee Steam Station		**370.0**	**372.0**		
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**176.0**	**176.0**		
Lee	7C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**82.0**	**82.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**853.4 MW**	**997.2 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	2	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	3	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	4	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**780.0**	**780.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2140.0 MW**	**2140.0 MW**		
Cedar Creek	1	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	2	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	3	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek Hydro Station		**45.0**	**45.0**		
Dearborn	1	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	2	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	3	14.0	14.0	Great Falls, S.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Dearborn Hydro Station		**42.0**	**42.0**		
Fishing Creek	1	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals Hydro Station		**2.0**	**2.0**		
Great Falls	1	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	2	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	3	0	0	Great Falls, S.C.	Hydro
Great Falls	4	0	0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	7	0	0	Great Falls, S.C.	Hydro
Great Falls	8	0	0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**12.0**	**12.0**		
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**0**	**0**		
Wateree	1	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	2	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	3	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	4	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	5	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree Hydro Station		**85.0**	**85.0**		
Wylie	1	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	2	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	3	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	4	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie Hydro Station		**72.0**	**72.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	0	0	Blacksburg, S.C.	Hydro
99 Islands	6	0	0	Blacksburg, S.C.	Hydro
99 Islands Hydro Station		**6.4**	**6.4**		
Keowee	1	76.0	76.0	Seneca, S.C.	Hydro
Keowee	2	76.0	76.0	Seneca, S.C.	Hydro
Keowee Hydro Station		**152.0**	**152.0**		
TOTAL S.C. HYDRO		**465.4 MW**	**465.4 MW**		
TOTAL S.C. CAPABILITY		**8,624.8 MW**	**8,895.6 MW**		

Table 5.C
Total Generation Capability [a,b,c,d,e]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	**20,868.4**	**21,642.0**

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Summer and winter capability reflects system configuration as of June 22, 2011.

Note d: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note e: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%

Changes to Existing Resources

Duke Energy Carolinas will adjust the capabilities of its resource mix over the 20-year planning horizon. Retirements of generating units, system capacity uprates and derates, purchased power contract expirations, and adjustments in EE and DSM capability affect the amount of resources Duke Energy Carolinas will need to meet its load obligation. Below are the known and/or anticipated changes and their respective impacts on the resource mix.

New Cliffside Pulverized Coal Unit
In March 2007, Duke Energy Carolinas received a CPCN for the 825 MW Cliffside 6 unit, which is scheduled to be on line in 2012. As of June 2011, the project is over 80% complete.

Bridgewater Hydro Powerhouse Upgrade
The two existing 11.5 MW units at Bridgewater Hydro Station are being replaced by two 15 MW units and a small 1.5 MW unit to be used to meet continuous release requirements, which is scheduled to be available for the summer peak of 2012.

Jocassee Unit 1 and 2 Runner Upgrades
This project is completed. Capacity additions reflect a 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency of the new runners. These uprates were included in the 2011 IRP analysis.

Buck Combined Cycle Natural Gas Unit
The Company received the CPCN for this project in June 2008 and received the corresponding air permit in October 2008. The 620 MW Buck CC unit is scheduled to be operational by the end of 2011. Construction and commissioning activities are underway and the project is currently over 90% complete.

Dan River Combined Cycle Natural Gas Unit
The Company received the CPCN for this project concurrently with the CPCN for the Buck CC project in June 2008 and received its air permit for this project in August 2009. The 620 MW Dan River CC unit is scheduled to be operational by the end of 2012. Construction is underway and the project is currently over 50% complete.

Lee Steam Station Natural Gas Conversion
Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. Switching fuel sources from coal to natural gas could prove to be an economic solution to avoid adding costly pollution control equipment or replacing the 370 MW of capacity at an alternative site. For planning purposes Lee Steam Station will be retired as

a coal station the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.

Generating Units Projected To Be Retired

Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. Table 5.D reflects current assessments of generating units with identified decision dates for retirement or major refurbishment.

There are two requirements related to the retirement of 800 MWs of older coal units. The first, a condition set forth in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6, requires the retirement of the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit, and retirement of older coal-fired generating units (in addition to Cliffside Units 1-4) on a MW-for-MW basis, considering the impact on the reliability of the system, to account for actual load reductions realized from the new EE and DSM programs up to the MW level added by the new Cliffside unit[2]. The requirement to retire older coal is also set forth in the air permit for the new Cliffside unit, in addition to Cliffside Units 1-4, of 350 MWs of coal generation by 2015, an additional 200 MWs by 2016, and an additional 250 MWs by 2018. If the NCUC determines that the scheduled retirement of any unit identified for retirement pursuant to the Plan will have a material adverse impact of the reliability of electric generating system, Duke Energy Carolinas may seek modification of this plan.

Additionally, multiple environmental regulatory issues are presently converging as the EPA has proposed new rules to regulate multiple areas relating to generation resources. These new rules, if implemented, will increase the need for the installation of additional control technology or retirement of coal fired generation in the 2014 to 2018 timeframe. Anticipating that there will be increased control requirements, the Carolinas 2011 IRP incorporates a planning assumption that all coal-fired generation that does not have an installed SO_2 scrubber will be retired by 2015.

Table 5.D shows the assumptions used for planning purposes rather than firm commitments concerning the specific units to be retired and/or their exact retirement dates. The conditions of the units are evaluated annually and decision dates are revised as appropriate. Duke Energy Carolinas will develop orderly retirement plans that consider the implementation, evaluation, and achievement of EE goals, system reliability

[2] NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007.

considerations, long-term generation maintenance and capital spending plans, workforce allocations, long-term contracts including fuel supply and contractors, long-term transmission planning, and major site retirement activities.

Table 5.D
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	EXPECTED RETIREMENT	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	RETIRED	Conventional Coal
Buck 3*	75	Salisbury, N.C.	RETIRED	Conventional Coal
Cliffside 1*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 2*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 3*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 4*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Dan River 1*	67	Eden, N.C.	4/01/2012	Conventional Coal
Dan River 2*	67	Eden, N.C.	3/01/2012	Conventional Coal
Dan River 3*	142	Eden, N.C.	4/01/2012	Conventional Coal
Buzzard Roost 6C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 7C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 8C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 9C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 10C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 11C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 12C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 13C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 14C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 15C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Riverbend 8C**	0	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 9C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 10C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 11C**	20	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Buck 7C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 8C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 9C**	12	Spencer, N.C.	6/01/2012	Combustion Turbine
Dan River 4C**	0	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 5C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 6C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Riverbend 4*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 6***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 7***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Buck 5***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Buck 6***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Lee 1***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 2***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 3***	170	Pelzer, S.C.	10/01/2014	Conventional Coal

Notes:

* Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

** The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

*** For the 2011 IRP process, remaining coal units without scrubbers were assumed to be retired by 2015. Based on the continued increased regulatory scrutiny from an air, water and waste perspective, these units will likely either be required to install additional controls or retire. If final regulations or new legislation allows for latitude in the retirement date if a retirement commitment is made versus adding controls, the retirement date may be adjusted.

Fuel Supply

Duke Energy Carolinas' current fuel usage consists primarily of coal and uranium. Oil and gas are currently used for peaking generation, but natural gas usage will expand when the Buck and Dan River Combined Cycle units are brought on-line.

Coal

Until the economic downturn in 2008, Duke Energy Carolinas had burned approximately 19 million tons of coal annually. However, the burn dropped drastically in 2009 before recovering somewhat in 2010 to around 15 million tons of coal, a level that is projected to be maintained over the next few years.

The Company primarily procures coal from Central Appalachian (CAPP) coal mines and delivered by the Norfolk Southern and CSX Railroads. The Company continually assesses coal market conditions to determine the appropriate mix of contract and spot market purchases in order to reduce exposure to the risk of price fluctuations. The Company also evaluates its diversity of coal supply from sources throughout the United States and internationally.

Although CAPP coal market prices are well below the all-time highs experienced in 2008, low gas prices have displaced some of the demand for CAPP from marginal units. Projected market prices for CAPP two years out are 20-50% higher than those seen in 2010, reflecting higher production costs combined with a more balanced supply and demand picture. Increasingly strict federal safety regulations and surface mine permit requirements in Central Appalachia could result in lower production and corresponding higher prices (relative to other coal produced in other basins.) For this reason, the Company is exploring means to develop greater supply and transportation flexibility in order to minimize the Company's dependency on CAPP.

Natural Gas

Duke Energy is still feeling the effects of the supply and demand imbalance which began during the fall of 2008 as the economy stumbled and new supplies of gas from unconventional sources came on line. Gas prices tumbled in 2009 to the $4/mmbtu range and the NYMEX forward market has continued to trade within a very narrow band over the past year as new supplies from shale resources continue to outpace the demand growth from the recovering industrial sector. This imbalance should start to wane in 2012, however, as several new factors begin to weigh on the market.

The first factor is the shift in drilling capital away from dry natural gas toward oil shales or gas shales that are rich in natural gas liquids (NGLs). NGLs include ethane, butane, propane and natural gasoline, and have various uses. A shift is already being seen in the Haynesville and Barnett regions, which were the early "game changers" in this area. With oil futures holding steady near $100/barrel and gas futures down in the $4 - $6/MMBTU range, the Company has perceived a strategic shift to oil/liquids directed drilling.

The second factor which will add near-term pressure to the market is the recently promulgated CSAPR for SO_2 and NO_x, scheduled to go into effect on Jan 1, 2012. Duke Energy Carolinas anticipates that CSAPR will push uncontrolled or un-scrubbed coal units higher in the dispatch order and further extend the gas displacement of coal; this is already occurring in areas where CAPP coal is the primary coal fuel source.

The third factor is the recovery in the petro-chemical demand for gas. A weak U.S. dollar coupled with a huge advantage in feedstock price, domestic gas versus global oil priced gas contracts, will lead to sustained growth in industrial gas demand. The size of the U.S. natural gas resource base has grown immensely over the past few years, but not all of these resources will remain economic at the current market price. Improvements are expected in the drilling and completion process of shale resources, and new regulations are likely to address a host of environmental concerns like methane migration into residential wells, fugitive methane emissions during the drilling process, produced water capture, storage and recycling. These issues will lead to technical solutions, but likely at a higher cost.

Nuclear Fuel

To provide fuel for Duke Energy Carolinas' nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, Duke Energy Carolinas staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply.

Due to the technical complexities of changing suppliers of fuel fabrication services, Duke Energy Carolinas generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a kWh basis will likely continue to be a fraction of the kWh cost of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

B. RENEWABLE RESOURCES AND RENEWABLE ENERGY INITIATIVES

1. Overview of Planning Assumptions

Duke Energy Carolinas' plans regarding renewable energy resources within this IRP are based primarily upon the presence of existing renewable energy requirements as well as the potential introduction of additional renewable energy requirements in the future.

Regarding existing renewable requirements, the Company is committed to meeting the requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). This is a statutory requirement enacted in 2007 mandating that Duke Energy Carolinas supply the equivalent of 12.5% of retail electricity sales in

North Carolina from eligible renewable energy resources and/or energy efficiency savings by 2021.

With respect to potential new renewable energy portfolio standard requirements, the Company's plans in this IRP account for the possibility of future requirements that will result in additional renewable resource development beyond the NC REPS requirements. Renewable requirements have been adopted in many states across the nation, and have also been contemplated as a federal measure and by members of the legislature in South Carolina. As such, the Company believes it is reasonable to plan for additional renewable requirements within the IRP beyond what presently exists with the NC REPS requirements.

Although there are many potential assumptions that could be made regarding such future renewable requirements, the Company has assumed in this IRP that a new legislative requirement (imposed by either federal or state level legislation) would be implemented in the future that would result in additional renewable resource development in South Carolina. For planning purposes, it is assumed that the requirement would be similar in many respects to the NC REPS requirement, but with a different implementation schedule. Specifically, the Company has assumed that this requirement would have an initial 3% milestone in 2016 and would gradually increase to a 12.5% level by 2030. Similar to NC REPS, this assumed legislative requirement would incorporate both renewable energy and energy efficiency, as well as a limited capability to utilize out of state unbundled purchases of Renewable Energy Certificates (REC or RECs). Further, this assumed requirement would have a solar set-aside requirement comparable to that in NC REPS, but would not contain any additional set-asides such as the poultry waste or swine waste set-aside requirements that are part of NC REPS. Finally, no assumptions related to a cost-cap feature that may limit development of renewables and ultimate cost to customers were made with this assumed legislation, whereas the Company's projections of renewable resource development for NC REPS are governed by the statutory cost caps within the law.

The Company has assessed the current and potential future costs of renewable and traditional technologies and, based on this analysis, the IRP modeling process shows that, for the most part, the amount of renewable energy resources that will be developed over the planning horizon will be defined by the existing and anticipated statutory renewable energy requirements described above. In other words, the IRP modeling does not indicate any material quantity of renewable resource development over and above the required levels due to lack of cost-effectiveness of these resources.

2. Summary of Expected Renewable Resource Capacity Additions

Based on the planning assumptions noted above regarding current and potential future renewable energy requirements, the Company projects that a total of approximately 800 MW (nameplate) of renewable energy resources will be interconnected to the Duke Energy Carolinas system by 2023, with that figure growing to approximately 884 MW by the end of the planning horizon in 2031. Actual results could vary substantially, with key drivers of different outcomes being future legislative requirements; relative costs of various renewable technologies in relation to traditional technologies; and various impediments impacting the development of various resources including permitting requirements, transmission and interconnection issues, or other matters.

It should be noted that many renewable technologies are intermittent in nature and that they therefore may not be contributing energy or capacity benefits to the Company's load requirements at any particular point in time. The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution towards the Company's peak load needs, are summarized in Table 5.E below.

Table 5.E Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2011	15.0	12	20	46	100	24	20	143
2012	0.0	12	29	41	0	24	29	53
2013	0.0	12	33	44	0	24	33	56
2014	15.0	12	89	116	100	24	89	213
2015	15.6	21	91	128	104	42	91	237
2016	47.8	22	179	249	318	45	179	542
2017	47.8	23	180	250	319	45	180	543
2018	49.7	24	230	304	332	49	230	610
2019	50.7	25	265	341	338	51	265	654
2020	53	28	296	376	352	56	296	703
2021	51	26	295	372	339	51	295	686
2022	55	28	344	427	367	57	344	767
2023	55	36	346	437	368	72	346	786
2024	55	36	347	439	369	73	347	789
2025	58	36	384	478	389	73	384	846
2026	61	41	386	488	406	81	386	874
2027	59	37	385	481	392	73	385	851
2028	59	37	388	484	393	74	388	855
2029	62	41	391	493	411	82	391	884
2030	62	41	391	493	411	82	391	884
2031	62	41	391	493	411	82	391	884

3. Changes in Renewable Planning Assumptions Since 2010

The renewable energy requirements (existing and anticipated) that are assumed in this IRP are largely similar to what was assumed in the Company's 2010 IRP. However, the Company's expectations regarding how those requirements will be met have evolved. Changes from the prior year are summarized here.

As compared to last year's IRP, the Company has assumed the development and interconnection of more wind resources over the planning horizon, along with a corresponding reduction in the development of biomass resources. The projected increase in wind resources is driven by the Company's observations that land-based wind developers are presently pursuing projects of significant size in North Carolina. The Company believes it is reasonable to expect that land-based wind will be developed in both North and South Carolina within the planning horizon to a degree that exceeds what was expected a year ago. The Company also has observed that opportunities currently exist, and may continue to exist, to transmit land-based wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

The Company's expectations regarding biomass resources are somewhat more modest, particularly in the near-term, than a year ago. This reduction in reliance upon biomass is in part due to uncertainties around the developable amount of such resources in the Carolinas, uncertainties related to the EPA's various rulemaking proceedings, and the projected availability of other forms of renewable resources to offset the needs for biomass. Because of the increased contributions from wind, which is an intermittent resource, versus biomass, which more closely mirrors a baseload resource, the Company has an additional system peak need in 2015.

In this current IRP, the Company also projects it will utilize more short term contracts than was assumed a year ago in the later years of the planning horizon. This is driven by a combination of factors, including an assumption that in the outer years of the planning horizon (e.g. beyond ~2023) there will be a more liquid market where the Company could engage in shorter term purchases of qualifying renewable energy or RECs to meet its REPS compliance needs. While the characteristics of this more distant portion of the planning horizon are difficult to ascertain with confidence, the Company projects that shorter term contracts may in fact be a necessity in order to effectively manage expenditures in accordance with the NC REPS statutory per-account cost caps, which remain fixed after 2015.

Through 2023, the Company's plans are based predominately on resources that are longer term in nature, with a gradual increase in the total amount of renewable resources over this time period. Beyond 2023, Duke Energy Carolinas forecasts that it will need additional resources to maintain compliance with NC REPS, with at least some of those resources being secured under short-term agreements. In this IRP, short-term agreements are assumed to come from a combination of unbundled in-state RECs from resources of various types, potentially including thermal RECs from Combined Heat and Power (CHP) facilities, as well as bundled energy and REC purchases of various resource types.

4. Further Details on Compliance with NC REPS

A more detailed discussion of the Company's plans to comply with the NC REPS requirements can be found in the Company's NC REPS Compliance Plan (Compliance Plan), which the Company submits to the NCUC as a separate document within the same docket as this IRP.

Details of that Compliance Plan are not duplicated here, although it is important to note that various details of the NC REPS law have impacts on the amount of energy and capacity that the Company projects to obtain from renewable resources to help meet the Company's long term resource needs. For instance, NC REPS contains several detailed parameters, including technology specific set-aside requirements for solar, swine waste, and poultry waste resources; capabilities to utilize EE savings and unbundled REC purchases from in-state or out-of-state resources, and RECs derived from thermal (non-electrical) energy; and a statutory spending limit to protect customers from cost increases stemming from renewable energy procurement or development. Each of these features of NC REPS has implications on the amount of renewable energy and capacity the Company forecasts to obtain over the planning horizon of this IRP. Additional details on NC REPS compliance can be found in the Company's Compliance Plan.

C. SUPPLY-SIDE RESOURCE SCREENING

For purposes of the 2011 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including pulverized coal units with and without carbon capture sequestration, Integrated Gasification Combined Cycle (IGCC) with and without carbon capture sequestration, CTs, CC units, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind, biomass, and solar in this year's screening analysis. Landfill gas was not included in this screening process due to limited availability. However, to the extent that landfill gas is available, it is competitive from a cost perspective with conventional baseload technologies.

For the 2011 IRP screening analyses, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, and renewable, with the ultimate goal of screening being to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for performing these initial screening analyses is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary because of the size of the problem to be solved and computer execution time limitations of the System Optimizer capacity model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following: Duke Energy's New Generation, Emerging Technologies, Duke Energy Analytical and Investment Engineering Teams, the EPRI Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Company personnel, or from other sources such as those mentioned above, or a combination of the two. The EPRI information along with any information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current and include similar scope across the technology types being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's construction material, manufactured equipment, and commodity markets, remains very difficult.

Technical Screening

The first step in the Company's supply-side screening process for the IRP was a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Carolinas service territory. A brief explanation of the technologies excluded at this point and the logic for their exclusion follows:

- Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.

- Advanced Battery storage technologies (Lead acid, Li-ion, Sodium Ion, Zinc Bromide, Fly wheels, pump storage) remain relatively expensive and are generally suitable for small-scale emergency back-up and/or power quality applications with short-term duty cycles of three hours or less. In addition, the current energy storage capability is generally 100 MWh or less. Research, development, and demonstration continue within Duke Energy, but this technology is generally not commercially available on a larger utility scale. Currently Duke Energy is installing 36 MW advanced acid lead batteries at the Notrees wind farm in Texas that is scheduled for start-up in 2012. Duke Energy has other storage system test stations at the Envision Energy Center in Charlotte, which specifically include 2 Community Energy Storage (CES) systems of 24 kW.
- Compressed Air Energy Storage (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- Small and medium nuclear reactors are generally limited to less than 300 MW. The NRC has not licensed any smaller nuclear reactor designs at this point in time. Several designs including those by General Electric (GE), Babcock & Wilcox (B&W) and Westinghouse may seek licensing in 2012 and 2013.
- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.
- Poultry waste and hog waste digesters remain relatively expensive and are capable of generating 500 – 600 MWh or less annually. Research, development, and demonstration continue, but these technologies are generally not commercially available on a larger utility scale. The Company's detailed quantitative analysis in this IRP included evaluation of purchased power agreements for poultry waste-to-energy facilities due to the poultry waste set-aside requirements in the NC REPS.
- Off-shore wind, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permittable.

This technology remains expensive and has yet to actually be constructed anywhere in the United States. Duke Energy Carolinas has collaborated with the University North Carolinas to continue studying off-shore wind on the Carolinas coastal area.

- Combined cycle G-Class technology has been demonstrated on a utility scale and is comparable to the F-Class in terms of efficiency. Its development remains limited due to lack of experience. The combined cycle G-class technology is larger in size and is designed to operate primarily as base load and not suitable for the anticipated cycling operation.

Economic Screening

In the supply-side screening analysis, the Company used the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the System Optimizer analysis (discussed in Chapter 8). The Company derived its biomass fuel price from various vendor fuel and delivery prices. The biomass fuel price may vary in the future as more utilities begin to use biomass fuel.

The Company screened all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class, as well as the final screening across the general classes used a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes a levelized fixed $/kW-year value. This calculated value represents the cost of operating the technology at a zero capacity factor or not at all, *i.e.*, the Y-intercept on the graph (see the General Appendix for individual graphs). The model then calculates the variable costs, such as fuel, variable O&M, and emission costs associated with operating the technology at 100% capacity factor, or at full load, over its lifetime and the present worth is computed back to the start year. This levelized operating $/kW-year is next added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve".

The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some of the renewable resources that have known limited energy output, such as wind and solar, have screening curves limited to their expected operating range on the individual graphs.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

2. Screening Results

The results of the screening within each category are shown in Appendix C.

The Company passes on those technologies from each of the three general categories screened (Baseload, Peaking/Intermediate, and Renewables) which were the "best," i.e., the lowest levelized busbar cost for a given capacity factor range within each of these categories, to the quantitative analysis phase for further evaluation.

Duke Energy Carolinas included CC generation in the peaking intermediate screening curves for comparison purposes. However, based on the screen results, CC generation would also be cost effective as a base load technology.

The Company's model selected the following technologies for the quantitative analysis:

- Baseload – 800MW Supercritical Pulverized Coal
- Baseload – 630 MW IGCC
- Baseload – 2 x 1,117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x204MW CTs (7FA.05)
- Base Load/Intermediate/Peaking – 480 MW Unfired + 125MW Duct Fired + 45MW Inlet Evaporative Cooler Natural Gas CC
- Base Load/Intermediate/Peaking – 480 MW Unfired + 45MW Inlet Evaporative Cooler Natural Gas CC
- Renewable – 100 MW Woody Biomass
- Renewable – 150 MW Wind - On-Shore
- Renewable – 15 MW Landfill Gas
- Renewable – 25 MW Solar PV

3. Unit Size

The unit sizes selected for planning purposes generally are the largest technologies available today because they generally offer lower \$/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, O&M costs, emission costs, *etc.*), not merely on the \$/kW cost. In the case of very large unit sizes such as those utilized for the nuclear and/or IGCC technology types, if these are routinely selected as part of a least cost plan, joint ownership can and may be evaluated and pursued.

4. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types, such as simple-cycle CT units and CC units, are relatively well known and are estimated in the TAG® and can be obtained from architect and engineering (A&E) firms and/or equipment vendors. The Company also uses its experience with the scope and costs for such resources to confirm the reasonableness of the estimates. The cost estimates include step-up transformers and a substation to connect with the transmission system. Since any additional transmission costs would be site-specific and specific sites requiring additional transmission are unknown at this time, typical values for additional transmission costs were also added to the alternatives. For natural gas units, gas pipeline costs were also included in the cost estimates. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple-cycle CT units is about two years. For the CC units, the estimated lead time is about two to three years. For coal units, the lead time is approximately five years. For nuclear units, the lead time is approximately five years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so Company judgment is also incorporated into the analysis as necessary.

6. RD&D Efforts and Technology Advances

New energy and technology alternatives will be necessary to ensure a long-term sustainable electric future. Duke Energy Carolinas' research, development, and delivery (RD&D) activities enable Duke Energy Carolinas to track new options including modular and potentially dispersed generation systems (small and medium nuclear reactors), CTs, and advanced fossil technologies. The Company places emphasis on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new power generation technology to assure a strategic advantage in electricity supply and delivery. Duke Energy is also a member of EPRI.

Within the planning horizon of this forecast, Duke Energy Carolinas expects that significant advances will continue to be made in CT technology. Advances in stationary industrial CT technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

7. Coordination with Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that units larger than Duke Energy Carolina's requirements become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

D. WHOLESALE AND QF PURCHASED POWER AGREEMENTS

Duke Energy Carolinas is an active participant in the wholesale market for capacity and energy. The Company has issued RFPs for purchased power capacity over the past several years, and has entered into purchased power arrangements for over 2,000 MWs over the past 10 years. In addition, Duke Energy Carolinas has contracts with a number of Qualifying Facilities (QFs). Table 5.F shows both the purchased power capacity obtained through RFPs as well as the larger QF agreements. See Appendix I for additional information on all purchases from QFs.

Table 5.F
Wholesale Purchases & Purchased Power Agreements

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Catawba County	Newton	NC	4	4	8/23/1999	8/22/2014
Concord Energy, LLC	Concord	NC	9	9	TBD	12/31/2031
Davidson Gas Producers, LLC	Lexington	NC	2	2	12/1/2010	12/31/2030
Gas Recovery Systems, LLC	Concord	NC	3	3	2/1/2010	12/31/2030
Gaston County	Dallas	NC	4	4	TBD	12/31/2021
Greenville Gas Producers, LLC	Greer	SC	3	3	8/1/2008	Ongoing
Lockhart Power Company	Wellford	SC	2	2	4/1/2011	12/31/2020
MP Durham, LLC	Durham	NC	3	3	9/18/2009	12/31/2029
Salem Energy Systems, LLC	Winston-Salem	NC	4	4	7/10/1996	Ongoing
WMRE Energy, LLC	Kernersville	NC	2	2	3/31/2011	12/31/2026
Mayberry Solar LLC	Mt. Airy	NC	1	0	9/1/2011	8/31/2026
Solar Green Development, LLC	Charlotte	NC	1	0	10/1/2011	9/30/2026
Solar Green Development, LLC	Mint Hill	NC	1	0	12/1/2011	11/30/2026
SunEd DEC1, LLC	Lexington	NC	8	0	12/1/2009	12/31/2030
Other PV	Various	NC	1	0	Various	Ongoing
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	95	7/1/1996	6/30/2013
Northbrook Carolina Hydro, LLC	Various	NC & SC	6	6	12/4/2006	Ongoing
Town of Lake Lure	Lake Lure	NC	3	3	2/21/2006	2/20/2011
Misc. Small Hydro/Other	Various	Both	6	6	Various	Assumed Evergreen
Other Wholesale	Various	Both	119	119	Various	Ongoing

Notes: Solar PV Firm Capacity represents 50% contribution to peak

Summary of Wholesale and QF Purchased Power Commitments
(as of July 1, 2011)

	SUMMER 11	WINTER 10/11
Non-Utility Generation		
Traditional	102 MW	109 MW
Renewable *	47 MW	36 MW
Duke Energy Carolinas allocation		
of SEPA capacity	37.8 MW	37.8 MW
Other-Wholesale	81.3 MW	81.3 MW
Total Firm Purchases	268.1 MW	264.1 MW

* Renewable includes landfill gas and solar PV

Planning Philosophy with Regard to Purchased Power

Opportunities for the purchase of wholesale power from suppliers and marketers are an important resource option for meeting the electricity needs of Duke Energy Carolinas' retail and wholesale customers. Duke Energy Carolinas has been active in the wholesale purchased power market since 1996 and during that time has entered into contracts totaling 2500 MWs to meet customer needs. The use of supply side requests for proposal (RFPs) continues to be an essential component of Duke Energy Carolinas' resource procurement strategy. In particular, the purchased power agreements that the Company has entered into have allowed customers to enjoy the benefits of discounted market capacity prices and have provided flexibility in meeting target planning reserve margin requirements.

The Company's approach to resource selection is as follows:

The IRP process is used to identify the type, size, and timing of the resource need. In selecting the optimal resource plan, Duke Energy Carolinas begins with an optimization model that selects the resource mix that minimizes the present value of revenue requirements (PVRR) for a given set of assumptions. The levelized cost method used for generation options serves as a proxy for either self-build or long-term purchased power opportunities. From the optimization step, several diverse portfolios of resources are selected for further detailed production costing modeling and ultimate selection of a resource plan for the IRP.

Once a resource need is identified, the Company determines the options to satisfy that need and determines the near-term and long-term actions necessary to secure the resource. The options could include a self-build Duke Energy Carolinas-owned resource, a Duke Energy Carolinas-owned acquired resource (new or existing), or a purchased power resource. The Company consistently has issued RFPs for peaking and intermediate resource needs. For example, following the identification of peaking and intermediate resource needs, the Company issued a RFP in May 2007 for conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 timeframe and up to 2000 additional MW beginning in the 2013 timeframe. Potential bidders could submit bids for purchased power or for the acquisition of existing or new facilities. Ten bidders submitted a total of forty-five bids spanning time periods of two to thirty years. The bid evaluation considered price, operational flexibility, and location benefits. Ultimately, the Company determined that none of the proposed bids provided sufficient advantages to offset the multiple benefits of the proposed Buck and Dan River CC projects. The consideration of purchased power options was described in the Company's CPCN application for these facilities and addressed in testimony. The NCUC issued the CPCNs for the Buck and Dan River CC projects in June 2008.

The Company also issued a RFP for renewable energy proposals in 2007. This RFP process produced proposals for approximately 1,900 megawatts of electricity from alternative sources from 26 different companies. The bids included wind, solar, biomass, biodiesel, landfill gas, hydro, and biogas projects. The Company entered into PPAs for a large solar project and several landfill gas facilities. In addition, the Company continues to receive unsolicited proposals for renewable purchased power resources and has entered into several PPAs as a result of unsolicited proposals.

The 2011 IRP plans included approximately 2,890 MWs of "New CT" capacity, in addition to existing and committed resources for the Cliffside Modernization project and Buck and Dan River combined cycle projects, as well as Lee Nuclear. The "New CT" resources reflect an identified need for peaking capacity that will be refined in future IRPs and could be met through new self-build capacity, purchased power, additional DSM or any combination of the three.

Although Duke Energy Carolinas evaluates the competitive wholesale market for peaking and intermediate resources, the Company's purchased power philosophy does not currently include soliciting purchased power bids for baseload capacity. Duke Energy Carolinas views baseload capacity as fundamentally different from peaking and intermediate capacity. Currently, there are two key concerns with relying upon the wholesale market for baseload capacity. First, generation outside the control area could be subject to interruption due to transmission issues more so than generation within the control area. Second, supplier default could jeopardize the ability to provide reliable service. The Company therefore believes that Duke Energy Carolinas-owned baseload resources are the most reliable means for Duke Energy Carolinas to meet its service obligations in a cost-effective and reliable manner.

In addition, the Company examines unsolicited bids for purchased power or resource acquisitions and is alert to opportunities to purchase power or resources.

6. ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commission (FERC), EPA, and the NRC, as well as state commissions and agencies, is potentially impacted by state and federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the existing generation and choices for new generation.

Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations such as the current Clean Air Interstate Rule (CAIR) NO_x and SO_2 cap-and-trade program, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas will reduce SO_2 emissions by approximately 75 percent by 2013 from 2000 levels. The law also required additional reductions in NO_x emissions in 2007 and 2009, beyond those required by the CAIR rule, which Duke Energy Carolinas has achieved. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

The following Charts 6.A and 6.B show Duke Energy Carolinas' NO_x and SO_2 emissions reductions to comply with the 2002 NC CSA requirements and actual emission through 2010.

Chart 6.A

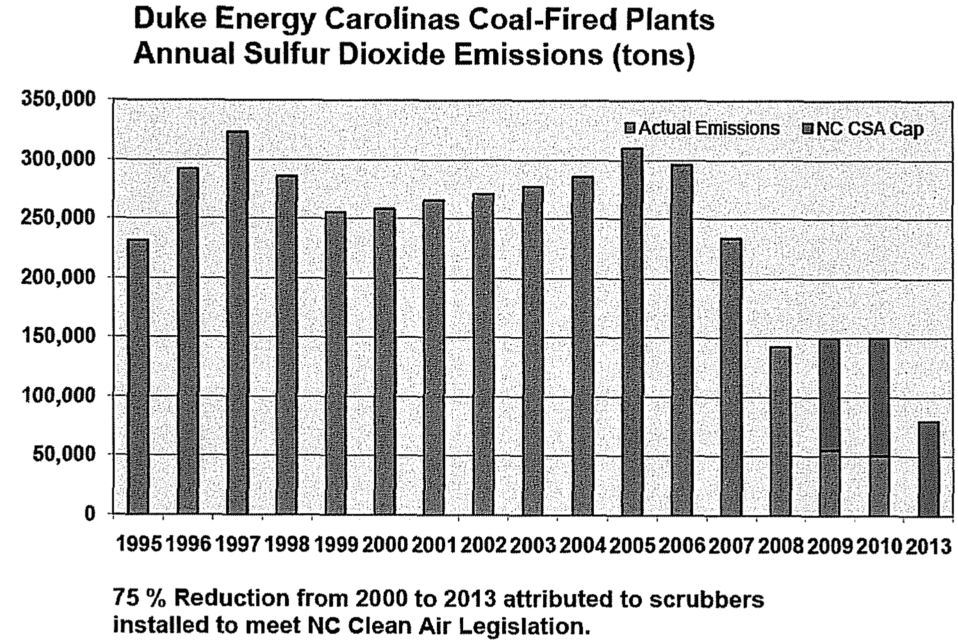
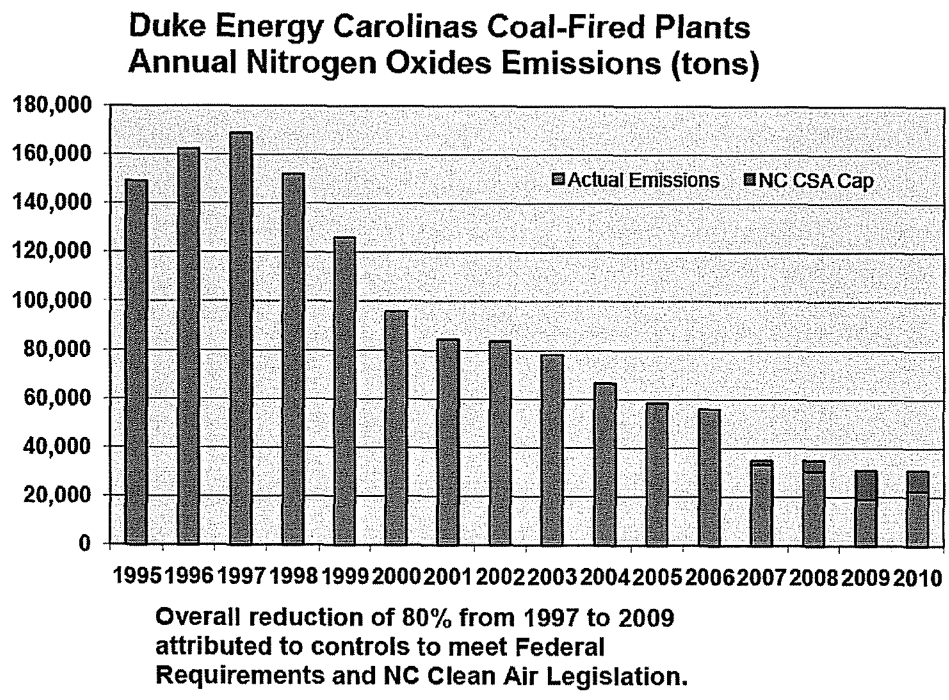


Chart 6.B



In addition to current programs and regulatory requirements, several new regulations are in various stages of implementation and development that will impact operations for

Duke Energy Carolinas in the coming years. Some of the major rules include:

Cross-State Air Pollution Rule – Replacement for Clean Air Interstate Rule (CAIR)

The EPA finalized its CAIR in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_x and in 2010 for SO_2. In July 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) issued its decision in *North Carolina v. EPA* vacating the CAIR. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA, allowing CAIR to remain in effect until EPA develops new regulations.

In August 2010, EPA published its proposed Transport Rule to replace the CAIR. On July 6, 2011, EPA issued the final rule, now known as the Cross-State Air Pollution Rule (CSAPR). The CSAPR replaces the CAIR and establishes state-level annual SO_2 and NO_x caps that take effect on January 1, 2012, and state-level ozone-season NO_x caps that take effect on May 1, 2012. The cap levels decline in 2014 in North Carolina, but remain constant in South Carolina. The CSAPR allows limited interstate and unlimited intrastate allowance trading. The final rule is significantly different from the original proposal. As a result, Duke Energy Carolinas has not had adequate time to prepare for these changes. Immediate steps are planned to develop strategies to minimize impacts while complying with the CSAPR. Duke Energy Carolinas will be particularly challenged to comply with annual and ozone season NO_x allocations in North Carolina beginning in 2014, as well as for both SO_2 and NO_x in South Carolina beginning in 2012. Additional revisions to the CSAPR could be developed by EPA that would incorporate the more stringent ozone and particulate matter NAAQS, which are in varying stages of development by the EPA.

Utility Boiler Maximum Achievable Control Technology (MACT)

In May 2005, the EPA issued the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act (CAA) section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008, the D.C. Circuit Court of Appeals issued its opinion, vacating the CAMR. EPA then began the process of developing a rule to replace the CAMR. The replacement rule, the Utility Boiler MACT, will create emission limits for hazardous air pollutants (HAPs), including mercury, from coal-fired and oil-fired power plants. Duke Energy completed work in 2010 as required for EPA's Utility MACT Information Collection Request (ICR). The ICR required collection of mercury and HAPs emissions data from numerous Duke Energy Carolinas facilities for use by EPA in developing the MACT rule. EPA published a proposed MACT rule (now referred to by EPA as the "Toxics Rule") on May 3, 2011 and expects to finalize it in November 2011. As proposed, the Toxics Rule is expected to require compliance with new emission limits in early 2015, with possible one-year extensions that a permitting authority can grant on a case-by-case basis. While the implications of the MACT rule are not fully known at this time, Duke Energy Carolinas is likely to face challenges from the rule which could include consideration of retiring certain assets rather than installing controls to comply.

Reciprocating Internal Combustion Engine (RICE) Maximum Achievable Control Technology (MACT)

EPA also has finalized the Reciprocating Internal Combustion Engine MACT (RICE MACT) which had an effective date of May 3, 2010. The RICE MACT requires certain existing engines such as those used for power production to retrofit with catalyst beds. While the RICE MACT has limited direct impact on the Company's operations, it does impact customers and suppliers of Duke Energy Carolinas and impacts purchasing agreements for the overall power supply portfolio. Non-emergency sources are most likely to be required to retrofit to comply with RICE standards. Engines used for emergency purposes, such as fire pumps and generators have limitations on operations and other less stringent requirements under the RICE MACT. These emergency-use engines will mostly be impacted with additional maintenance requirements, such as inspections, record keeping and periodic maintenance requirements. All engines will have to be in compliance by May 3, 2013, with costs to comply occurring in the 2011-2012 timeframe. This has impacted the Company's expected demand response program reductions identified in this IRP.

National Ambient Air Quality Standards (NAAQS)

8 Hour Ozone Standard

In March 2008 EPA revised the 8-hour ozone standard by lowering it from 84 to 75 parts per billion (ppb). In September 2009, EPA announced a decision to reconsider the 75 ppb standard. The decision was in response to a court challenge from environmental groups and EPA's belief that a lower standard was justified.

EPA issued a proposed rule on January 7, 2010 in which EPA proposed to replace the existing standard with a new standard between 60 and 70 ppb. EPA plans to issue a final rule in the fall of 2011. The schedule for implementing a new standard is somewhat uncertain until EPA finalizes the rule as well as its plans for implementation. It is estimated, however, that State Implementation Plans (SIP) could be due by December

2014, with possible attainment dates for most areas in the 2018 timeframe. Additional controls could be required by the 2018 ozone season. Until the states develop implementation plans, only an estimate can be developed of the potential impact to Duke Energy Carolina's generation fleet. A standard in the 60 to 70 ppb range is considered very stringent and will likely result in numerous non-attainment area designations.

SO_2 Standards

In November 2009, EPA proposed a rule to replace the 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. EPA finalized its new 1-hr standard of 75 ppb in June 2010. EPA will have 2 years (June 2012) to designate areas relative to their attainment status with the new standard. States with non-attainment areas will have until the January 2014 to submit their SIPs. Initial attainment dates are expected to be the summer of 2017. EPA has not yet indicated when any required controls might need to be in place, but is expected by late-2016. EPA will base its nonattainment designations on monitored air quality data as well as on dispersion modeling. All power plants will be modeled by the NC and SC Department of Air Quality and are therefore potential targets for additional SO_2 reductions, even if there is no monitored exceedance of the standard. In addition, EPA is proposing to require states to relocate some existing monitors and to add some new monitors. Although these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas.

Particulate Matter (PM) Standard

On September 21, 2006, the EPA announced its decision to revise the $PM_{2.5}$ NAAQS standard. The daily standard was reduced from 65 ug/m^3 (micrograms per cubic meter) to 35 ug/m^3. The annual standard remained at 15 ug/m^3.

EPA finalized designations for the 2006 daily standard in October 2009, which did not include any nonattainment areas in the Duke Energy Carolinas service territory. On February 24, 2009, the D.C Circuit unanimously remanded to EPA the Agency's decision to retain the annual 15 ug/m^3 primary $PM_{2.5}$ NAAQS and to equate the secondary $PM_{2.5}$ NAAQS with the primary NAAQS. EPA must now undertake new rulemaking to revise the standards consistent with the Court's decision. EPA's current timeline indicates that it will propose a $PM_{2.5}$ rule in fall 2011 and possibly finalize a rule around mid-2012. The likely outcome of EPA's ongoing review will be a tightening of the primary daily and annual $PM_{2.5}$ NAAQS along with the creation of a separate secondary $PM_{2.5}$ NAAQS. The current annual and daily $PM_{2.5}$ standards alone are not driving any emission reductions at Duke Energy Carolinas facilities. The reduction in SO_2 and NO_x emissions to address the current annual standard are being addressed through CAIR.

Reductions to address the current daily standard will be addressed as part of the CSAPR that EPA developed to replace CAIR (the CSAPR will continue to address reductions needed for the current annual standard).

Greenhouse Gas Regulation

The EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule, which sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for GHGs. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2 will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Carolinas generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT at a particular point in time, the potential implications of this regulatory requirement are presently unknown.

In early 2011, EPA entered into a settlement agreement to issue New Source Performance Standards for GHG emissions from new and modified fossil fueled electric generating units (EGUs) and emission guidelines for existing EGUs. The agreement calls for regulations to be proposed by September 30, 2011 and to be finalized by 2012.

It is currently not known if or when any federal climate change legislation limiting GHG emissions might be enacted.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications and/or cooling towers for existing facilities to minimize impingement and entrainment of aquatic organisms. All Duke Energy Carolina's coal and nuclear generating stations are potentially affected sources under that rule.

EPA issued a proposed rule on April 20, 2011 and expects to finalize the rule in July 2012. Depending upon a station's National Pollutant Discharge Elimination System (NPDES) permit renewal schedule, compliance with the rule could begin as early as mid-2015.

EPA's proposed rule lists four options with a preference for one option. The preferred option impacts all facilities with a design intake flow greater than 2 million gallons per day (mgd). In order to meet fish impingement standards, intake screen modifications are likely to be needed for nearly all plant intakes. EPA has not mandated the use of cooling towers as "Best Technology Available" to address entrainment requirements. However, site specific studies are proposed by the rule in order to address best technology options for complying with the entrainment requirements. These studies could begin as early as 2013.

Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. In order to assist with development of the revised regulation, EPA issued an Information Collection Request (ICR) to gather information and data from nearly all steam-electric generating facilities. The ICR was completed and submitted to EPA in October 2010. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are FGD wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require dry ash handling systems be installed. Following review of the ICR data, EPA plans to issue a draft rule in July 2012 and a final rule in January 2014. After the final rulemaking, effluent guideline requirements will be included in a station's NPDES permit renewals. Thus, requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The length of time allowed to comply will be determined through the permit renewal process.

Coal Combustion Residuals

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion residuals (CCRs). CCRs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA, as it developed proposed regulations.

In June 2010, EPA issued its proposed rule regarding CCRs. The proposed rule offers two options: (1) a hazardous waste classification under Resource Conservation and Recovery Act (RCRA) Subtitle C; and (2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal could result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected until 2012 or 2013. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. The impact to Duke Energy Carolinas of this regulation as proposed is still being assessed. The schedule for compliance will depend upon when EPA finalizes a rule and the rule requirements.

7. TRANSMISSION AND DISTRIBUTION

A. Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The Duke Energy Carolinas' transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with Duke Energy Carolinas' Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades and are used as inputs into the Duke Energy Carolinas – Power Delivery optimization process. The Power Delivery optimization process evaluates problem-solution alternatives and their respective priority, scope, cost, and timing. The optimization process enables Power Delivery to produce a multi-year work plan and budget to fund a portfolio of projects which provides the greatest benefit for the dollars invested.

Duke Energy Carolinas currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. The Power Delivery optimization process is also used to manage projects for improvement of transfer capability.

The SERC audits Duke Energy Carolinas every three years for compliance with NERC Reliability Standards. Specifically, the audit requires Duke Energy Carolinas to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC completed a full audit in April 2008 and also completed a "spot check" audit of selected standards in August 2009. Duke Energy Carolinas was found compliant in all areas of the audit. SERC also conducted a full audit in May 2011. The 2011 audit results are not yet publically available.

Duke Energy Carolinas participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure the interconnected system's compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

B. Transmission System Emerging Issues

Looking forward, several items that have the potential to impact the planning of the Duke Energy Carolinas Transmission System include:

- Industry-approved revisions to the NERC Reliability Standards for transmission planning standards that are awaiting FERC approval.

- The FERC Final Order on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued in July 2011 under Docket No. RM10-23-000.

- Increased interest in the integration of variable renewable resources (e.g., wind) into the grid. The North Carolina Transmission Planning Collaborative and the DOE-funded Southeastern Offshore Wind Energy Infrastructure Project are performing studies in 2011 to assess the transmission impacts of significant off-shore wind development along the Southeast coast including North Carolina.

- The Eastern Interconnection Planning Collaborative (EIPC), which is a transmission study process that began in late 2009. The EIPC provides:

1. A mechanism to aggregate existing regional transmission plans in the Eastern Interconnection and assess them on an Eastern Interconnection wide basis; and
2. A framework to be able to perform technical analyses to inform state and federal government representatives and policy makers on important issues, such as future renewable resources and their impact on transmission infrastructure.

As of late July 2011, the EIPC is awaiting determination by its Stakeholder Steering Committee (SSC) of the three future scenarios they will request receive detailed analysis by the EIPC powerflow study group. The detailed analysis will determine the future transmission infrastructure required to support each of the three resource scenarios selected by the SSC.

- Duke Energy and Progress Energy are working towards a merger of the corporations and are targeting a closing by the end of 2011. The organizational structure and processes related to transmission planning in North Carolina are being discussed and evaluated by the management of the two companies.

8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of Duke Energy Carolinas' customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, Duke Energy Carolinas develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 17 percent target planning reserve margin (see Reserve Margin discussion below). The capability of existing resources, including generating units, energy efficiency and demand-side management programs, and purchased power contracts, is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meets the load obligation.

Reserve Margin Explanation and Justification

Reserve margins are necessary to help ensure the availability of adequate resources to meet load obligations due to consideration of customer demand uncertainty, unit outages, transmission constraints, and weather extremes. Many factors have an impact on the appropriate levels of reserves, including existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchased power market.

Duke Energy Carolinas' historical experience has shown that a 17 percent target planning reserve margin is sufficient to provide reliable power supplies, based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities, and procurement of purchased capacity. As part of the Company's process for determining its target planning reserve margins, Duke Energy Carolinas reviews whether the current target planning reserve margin is adequate in the prior period. From July 2006 through June 2011, generating reserves, defined as available Duke Energy Carolinas generation capacity plus the net of firm purchases less sales, never dropped below 450 MW. However, on June 1, 2011, the Company's generating reserves dropped to approximately 500 MWs due to above-normal temperatures and forced outages on several units. Since 1997, Duke Energy Carolinas has had sufficient reserves to meet customer load reliably with limited need for activation of interruptible programs. However, on June 1, 2011, 535 MWs of DSM were activated. The DSM Activation History in Appendix D illustrates Duke Energy Carolinas' limited activation of interruptible programs through June 2011.

Duke Energy Carolinas also continually reviews its generating system capability, level of potential DSM activations, scheduled maintenance, environmental retrofit equipment and environmental compliance requirements, purchased power availability, and transmission capability to assess its capability to reliably meet customer demand. There are a number of increased risks that need to be considered with regard to Duke Energy Carolinas' reserve margin target. These risks include: (1) the increasing age of existing units on the system; (2) the inclusion of a significant amount of renewables (which are generally less available than traditional supply-side resources) in the plan due to the enactment of the NC REPS; (3) uncertainty regarding the impacts associated with significant increases in the Company's energy efficiency and demand-side management programs; (4) longer lead times for building baseload capacity such as nuclear; (5) increasing environmental pressures, which may cause additional unit derates and/or unit retirements; and (6) increases in derates of units due to extreme hot weather and drought conditions. Each of these risks would negatively impact the resources available to provide reliable service to customers. Duke Energy Carolinas will continue to monitor these risks in the future and make any necessary adjustments to the reserve margin target in future plans.

Duke Energy Carolinas also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability, due to greater knowledge of near-term weather conditions and generation unit availability.

Duke Energy Carolinas uses adjusted system capacity[3], along with Interruptible DSM capability to satisfy Duke Energy Carolinas' NERC Reliability Standards requirements for operating and contingency reserves. Contingencies include events such as higher than expected unavailability of generating units, increased customer load due to extreme weather conditions, and loss of generating capacity because of extreme weather conditions such as the severe drought conditions in 2007.

Upon the completion of the merger between Duke Energy and Progress Energy, the combined system reserve margin will be comprehensively reviewed to determine if the reserve margin needs to be adjusted.

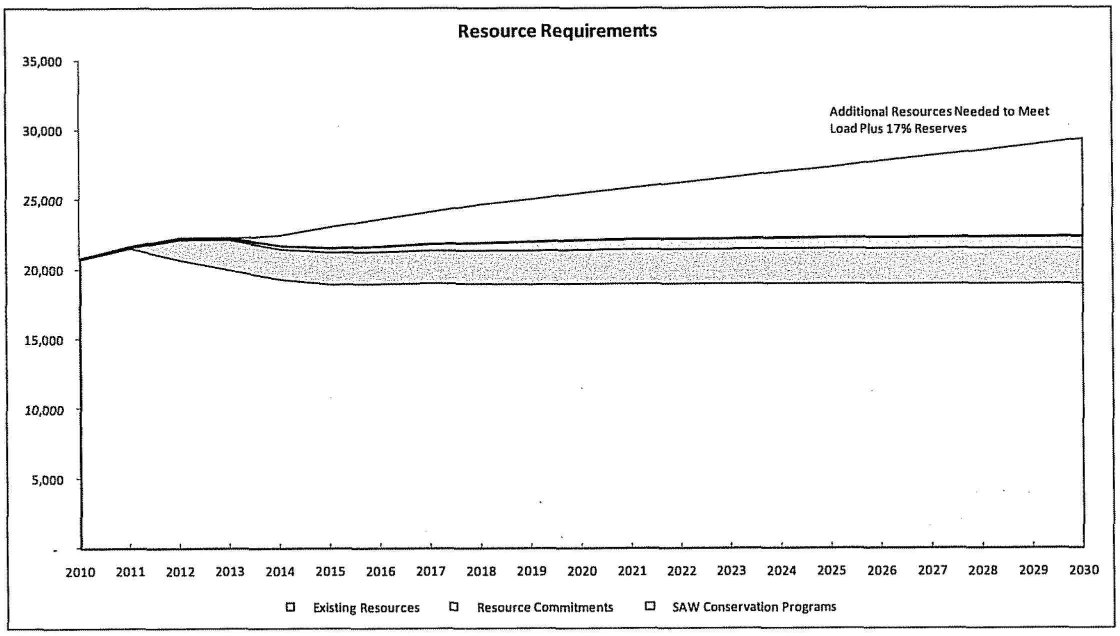
[3] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased power capacity.

Load and Resource Balance

The following chart shows the existing resources and resource requirements needed to meet the Company's load obligation, plus the 17 percent target planning reserve margin. Beginning in 2011, existing resources, consisting of existing generation and purchased power to meet load requirements, total 20,777 MW. The load obligation plus the target planning reserve margin is 20,547 MW, indicating sufficient resources to meet Duke Energy Carolinas' obligation. The need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, and expirations of purchased-power contracts. The need grows to approximately 3,090 MW by 2020 and to 7,030 MW by 2031. Assumptions made in the development of this chart include:

1. Cliffside Unit 6 is built by the summer of 2012 and therefore included in Resource Commitments;
2. Coal retirements associated with the Cliffside Unit 6 CPCN and Air Permit, Buck Units 5&6, and Lee Steam Station are included;
3. Retirement of the old fleet combustion turbines;
4. Conservation programs associated with the save-a-watt program are included;
5. DSM programs associated with the save-a-watt program are included;
6. Buck/Dan River combined cycle facilities are included in Resource Commitments;
7. Renewable capacity is built or purchased to meet the NC REPS

Chart 8.A
Load and Resource Balance



Cumulative Resource Additions to Meet a 17 Percent Planning Reserve Margin (MWs)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Resource Need	0	0	0	790	1550	1990	2330	2790	3090	3410
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Resource Need	3730	4080	4430	4780	5080	5520	5890	6220	6630	7030

B. OVERALL PLANNING PROCESS CONCLUSIONS

Duke Energy Carolinas' resource planning process provides a framework for the Company to access, analyze and implement a cost-effective approach to reliably meet customers' growing energy needs. In addition to assessing qualitative factors, the Company has also conducted a quantitative assessment using simulation models.

Duke Energy Carolinas tested a variety of sensitivities and scenarios against a base set of inputs for various resource mixes, allowing the Company to better understand how potentially different future operating environments due to fuel commodity price changes, environmental emission mandates, and structural regulatory requirements can affect resource choices, and, ultimately, the cost of electricity to customers. (Appendix A provides a detailed description and results of the quantitative analyses).

The results of the Company's quantitative analyses suggest that a combination of additional baseload, intermediate and peaking generation, renewable resources, EE, and DSM programs is required over the next twenty years to meet customer demand reliably and cost-effectively.

The new pulverized coal unit at Cliffside Steam Station (Unit 6) is assumed to be in service in 2012, annually providing 5,700 GWh of baseload energy. Project implementation is underway for the new CC facilities at Buck and Dan River, with the facilities assumed to be operational in late 2011 and late 2012, respectively. In addition, Duke Energy Carolinas has included DSM, EE and renewable resources consistent with the Company's energy efficiency plan approved in North and South Carolina and to meet the NC REPS. For planning purposes, approximately 5% of retail sales in South Carolina would come from renewable energy, in addition to the energy efficiency programs, phased in from 2015 to 2031. The Company's analysis for the 2010 IRP demonstrated that approximately 200 MWs of nuclear uprates were cost effective and specific projects are being developed to be implemented in the 2011-2019 timeframe. For planning purposes, Lee Steam Station will be retired from coal fired generation and converted to natural gas generation in 2015. The increase in the peak generation need in 2015 is primarily due to increased load projections, updated assumptions regarding the energy impacts of CFLs and lower projected capacity impacts from DSM programs, as well as changes in the projected compliance portfolio relating to the NC REPS.

The Company's analysis of new nuclear capacity contained in the 2011 IRP focuses on the impact of various uncertainties such as load variations, nuclear capital costs, greenhouse gas and clean energy legislation, EPA regulations, fuel prices, and the availability of financing options such as federal loan guarantees (FLG).

The IRP analysis included sensitivities on each of the uncertainties described below:

Load Variations: The base case load forecast incorporates the impact of the current recession, projected EE achievements, demand destruction associated with the implementation of carbon legislation, new wholesale sales opportunities, and the impact associated with future plug-in hybrid vehicles. The Company also developed high and low load forecast sensitivities to reflect a 95% confidence interval.

Nuclear Capital Costs: The Company varied the nuclear capital cost on the low end to reflect the impact of minimal project contingency and varied on the high side to reflect increased labor and material cost.

Greenhouse Gas Legislation: The 2011 fundamental CO_2 allowance price forecast was lower primarily due to uncertainty of Congress to pass legislation. For the 2011 IRP, the Company evaluated a range of CO_2 prices based on various legislative cap and trade proposals used in 2009 and 2010 IRPs, in addition to potential Clean Energy legislation that does not have a CO_2 cap and trade mechanism, but relies upon a federal RPS.

Fuel Prices: The base case natural gas and coal price projections were based on Duke Energy's fundamental price forecasts, which are updated annually. The Company also evaluated a high cost fuel scenario, which reflects the impact of increased demand on natural gas and regulatory challenges to the coal mining industry. The lower cost fuel scenario represents a larger supply of domestic natural gas than currently assumed and a lower demand on coal.

Nuclear Financing Options: The nuclear cost referenced as "traditional financing" in the 2011 IRP includes state incentives, local incentives, and the ability to recover construction financing cost prior to commercial operation. Duke Energy Carolinas continues to believe that legislation allowing for timely collection of financing cost outside a general rate case during construction (nuclear financing legislation) is critical to the development of new nuclear plants. The Company plans to pursue nuclear financing legislation in the 2012 NC legislative session. Duke Energy Carolinas believes this legislation is important to demonstrate support for new nuclear development, and to allow utilities investing in new nuclear construction to maintain the strength of their respective balance sheets during construction to the benefit of their customers.

The nuclear cost referenced as "favorable financing" includes FLGs. The Company evaluated these credits as sensitivities because Duke Energy Carolinas' proposed Lee Nuclear Station does not currently qualify for these incentives. However, it is important to continue to include these benefits as sensitivities because it demonstrates how much expansion of these programs could lower the ultimate costs to customers, should the project qualify. There is federal legislative support for expanding these programs in the future.

Results

The results of the Company's quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and EE and DSM programs are required over the next 20 years. The near-term resource needs can be met, in part, with new EE and DSM programs, completing construction of the Buck, Dan River, and Cliffside Projects, completion of various fossil and hydro unit uprates, as well as pursuing nuclear uprates and renewable resources. However, additional resources will be needed as early as 2015 due to increased load projections, updated assumptions regarding the energy impacts of CFLs, lower projected capacity impacts from DSM programs, and changes in the projected renewable compliance portfolio. The Company's analysis continues to affirm the potential benefits of new nuclear capacity in the 2020 timeframe in a carbon-constrained future. The Company expects to receive the COL for the Lee Nuclear Station project in early 2013 and will make a final decision on the construction of the project based on the market conditions at that time, including the status of nuclear financing legislation in North Carolina.

To demonstrate that the Company is planning adequately for customers, the Company selected a portfolio incorporating the impact of future carbon legislation for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table).

This portfolio consisted of 2,890 MW[4] of new natural gas simple cycle capacity, 1,300 MW of CC capacity, 2,234 MW of new nuclear capacity, 987 MW of DSM, 727 MW of EE, and 484 MW of renewable resources. The selected portfolio specifically includes the Cliffside Unit 6, Buck CC, and Dan River CC projects.

However, the Company will likely face significant challenges relating to its resource planning in the future, such as specific challenges in (1) obtaining the necessary regulatory approvals to implement future demand-side, EE, and supply-side resources, (2) finding sufficient cost-effective, reliable renewable resources to meet the standard, (3) effectively integrating renewables into the resource mix, and (4) ensuring sufficient transmission capability for these resources. In light of the myriad of qualitative issues facing the Company relating to its fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers'

[4] The ultimate sizes of any generating unit may change somewhat depending on the vendor selected.

energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

On July 12, 2011, the NRC task force on the Japanese Fukishima Dai-ichi event noted it had not identified any issues that undermine confidence in the continued safety and emergency planning of U.S. nuclear plants. The task force review is ongoing and is likely to result in additional actions to enhance safety and preparedness of the U.S. nuclear fleet. The nuclear industry will ensure an exhaustive review of the events in Japan is completed and all possible lessons learned are applied to further improve nuclear safety. At this time, no significant impacts on new nuclear plant licensing are anticipated as a result of the events in Japan.

The Oconee Nuclear Station's (Oconee) current operating license expires in 2033, which is close to the end of our current IRP planning horizon. At this time, the Company has not made a decision concerning a second license extension for this plant. Oconee is a significant part of our generation portfolio representing over 2,500 MW of capacity and annual energy output of approximately 20,000 GWHrs. As such, it is important to start to examine the impacts of any potential retirement of Oconee to help the Company as it considers a second license extension, as well as incorporate these impacts into the resource planning process.

The planning process must be dynamic and adaptable to changing conditions. While this plan is the most appropriate resource plan at this point in time, good business practice requires Duke Energy Carolinas to continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning analysis is truly an evolving process that can never be considered complete.

The seasonal projections of load, capacity, and reserves of the selected plan are provided in Table 8.A.

Table 8.A

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2011 Annual Plan

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast																				
1 Duke System Peak	17,892	18,347	18,800	19,239	19,752	20,220	20,675	21,122	21,444	21,826	22,152	22,469	22,777	23,120	23,399	23,777	24,109	24,417	24,765	25,121
Reductions to Load Forecast																				
2 New EE Programs	(80)	(102)	(120)	(208)	(276)	(343)	(410)	(478)	(544)	(611)	(622)	(633)	(642)	(655)	(667)	(679)	(688)	(703)	(715)	(727)
3 Adjusted Duke System Peak	**17,812**	**18,245**	**18,680**	**19,032**	**19,476**	**19,877**	**20,265**	**20,644**	**20,901**	**21,214**	**21,530**	**21,836**	**22,135**	**22,465**	**22,732**	**23,099**	**23,420**	**23,714**	**24,050**	**24,393**
Cumulative System Capacity																				
4 Generating Capacity	19,762	20,404	21,070	21,088	20,378	20,388	20,415	20,495	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525
5 Capacity Additions	1,465	666	18	370	10	27	81	30	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(824)	0	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,404	21,070	21,088	20,378	20,388	20,415	20,495	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525
Purchase Contracts																				
9 Cumulative Purchase Contracts	270	211	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0
11 Catawba Owner Load Following Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	740	1,480	1,480	2,130	2,130	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	3,520	3,520	4,190
Renewables	41	44	116	128	249	250	304	341	376	372	427	437	439	478	488	481	484	493	484	484
13 Cumulative Production Capacity	**20,715**	**21,326**	**21,281**	**21,300**	**22,171**	**22,198**	**22,983**	**23,050**	**23,822**	**24,980**	**25,027**	**26,154**	**26,156**	**26,195**	**26,205**	**26,198**	**26,201**	**26,860**	**26,851**	**27,521**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	2,903	3,081	2,600	2,268	2,694	2,321	2,718	2,406	2,921	3,766	3,497	4,318	4,021	3,731	3,473	3,099	2,780	3,146	2,801	3,128
15 % Reserve Margin	**16.3%**	**16.9%**	**13.9%**	**11.9%**	**13.8%**	**11.7%**	**13.4%**	**11.7%**	**14.0%**	**17.8%**	**16.2%**	**19.8%**	**18.2%**	**16.6%**	**15.3%**	**13.4%**	**11.9%**	**13.3%**	**11.6%**	**12.8%**
16 % Capacity Margin	14.0%	14.4%	12.2%	10.6%	12.2%	10.5%	11.8%	10.4%	12.3%	15.1%	14.0%	16.5%	15.4%	14.2%	13.3%	11.8%	10.6%	11.7%	10.4%	11.4%
Demand-Side Management																				
17 Cumulative DSM Capacity	838	850	919	983	987	986	986	986	986	986	986	986	986	986	986	986	986	986	986	986
IS / SG	181	147	140	133	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Power Share / Power Manager	657	703	780	851	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861
18 Cumulative Equivalent Capacity	21,553	22,175	22,200	22,283	23,157	23,184	23,969	24,036	24,808	25,967	26,013	27,140	27,142	27,182	27,191	27,184	27,187	27,847	27,837	28,507
Reserves w/ DSM																				
19 Generating Reserves	3,741	3,930	3,520	3,251	3,681	3,307	3,705	3,392	3,908	4,753	4,484	5,304	5,008	4,717	4,459	4,085	3,767	4,132	3,787	4,114
20 % Reserve Margin	**21.0%**	**21.5%**	**18.8%**	**17.1%**	**18.9%**	**16.6%**	**18.3%**	**16.4%**	**18.7%**	**22.4%**	**20.8%**	**24.3%**	**22.6%**	**21.0%**	**19.6%**	**17.7%**	**16.1%**	**17.4%**	**15.7%**	**16.9%**
21 % Capacity Margin	17.4%	17.7%	15.9%	14.6%	15.9%	14.3%	15.5%	14.1%	15.8%	18.3%	17.2%	19.5%	18.4%	17.4%	16.4%	15.0%	13.9%	14.8%	13.6%	14.4%

Winter Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2011 Annual Plan

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Load Forecast																				
1 Duke System Peak	17,425	17,869	18,303	18,746	19,180	19,665	20,123	20,539	20,868	21,128	21,482	21,782	22,080	22,379	22,649	22,922	23,280	23,584	23,885	24,186
Reductions to Load Forecast																				
2 New EE Programs	(67)	(96)	(126)	(204)	(289)	(360)	(429)	(497)	(564)	(636)	(647)	(658)	(668)	(681)	(693)	(706)	(716)	(730)	(743)	(756)
3 Adjusted Duke System Peak	**17,359**	**17,773**	**18,177**	**18,543**	**18,891**	**19,305**	**19,694**	**20,042**	**20,304**	**20,492**	**20,835**	**21,124**	**21,412**	**21,697**	**21,956**	**22,217**	**22,565**	**22,853**	**23,142**	**23,430**
Cumulative System Capacity																				
4 Generating Capacity	20,567	20,934	21,773	21,820	21,468	21,128	21,137	21,164	21,245	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275
5 Capacity Additions	684	1,465	46	18	370	10	27	81	30	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(311)	(626)	0	(370)	(710)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,934	21,773	21,820	21,468	21,128	21,137	21,164	21,245	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275
Purchase Contracts																				
9 Cumulative Purchase Contracts	277	218	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0
11 Catawba Owner Load Following Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	740	1,480	1,480	2,130	2,130	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	3,520	3,520
Renewables	46	41	44	116	128	249	250	304	341	376	372	427	437	439	478	488	481	484	493	484
13 Cumulative Production Capacity	**21,257**	**22,032**	**21,940**	**21,638**	**22,049**	**22,920**	**22,947**	**23,732**	**23,796**	**24,618**	**25,721**	**25,776**	**26,903**	**26,906**	**26,945**	**26,954**	**26,947**	**26,950**	**27,610**	**27,601**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	3,899	4,260	3,764	3,095	3,158	3,615	3,254	3,690	3,492	4,126	4,886	4,653	5,491	5,208	4,989	4,737	4,383	4,097	4,468	4,170
15 % Reserve Margin	**22.5%**	**24.0%**	**20.7%**	**16.7%**	**16.7%**	**18.7%**	**16.5%**	**18.4%**	**17.2%**	**20.1%**	**23.5%**	**22.0%**	**25.6%**	**24.0%**	**22.7%**	**21.3%**	**19.4%**	**17.9%**	**19.3%**	**17.8%**
16 % Capacity Margin	18.3%	19.3%	17.2%	14.3%	14.3%	15.8%	14.2%	15.5%	14.7%	16.8%	19.0%	18.1%	20.4%	19.4%	18.5%	17.6%	16.3%	15.2%	16.2%	15.1%
Demand-Side Management																				
17 Cumulative DSM Capacity	548	511	530	547	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555
IS / SG	181	147	140	133	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Power Share / Power Manager	367	364	391	414	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429
18 Cumulative Equivalent Capacity	21,806	22,544	22,471	22,184	22,604	23,475	23,502	24,287	24,351	25,172	26,276	26,331	27,458	27,460	27,499	27,509	27,502	27,505	28,164	28,155
Reserves w/ DSM																				
19 Generating Reserves	4,447	4,771	4,294	3,641	3,713	4,169	3,808	4,245	4,047	4,680	5,441	5,207	6,046	5,763	5,544	5,292	4,937	4,652	5,023	4,725
20 % Reserve Margin	**25.6%**	**26.8%**	**23.6%**	**19.6%**	**19.7%**	**21.6%**	**19.3%**	**21.2%**	**19.9%**	**22.8%**	**26.1%**	**24.7%**	**28.2%**	**26.6%**	**25.2%**	**23.8%**	**21.9%**	**20.4%**	**21.7%**	**20.2%**
21 % Capacity Margin	20.4%	21.2%	19.1%	16.4%	16.4%	17.8%	16.2%	17.5%	16.6%	18.6%	20.7%	19.8%	22.0%	21.0%	20.2%	19.2%	18.0%	16.9%	17.8%	16.8%

Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer and Winter Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 91 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

5. Capacity Additions reflect an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2012.
   Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Buck and Dan River Combined Cycle facilities).
   Capacity Additions include the conversion of Lee Steam Station from coal to natural gas in 2015.
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2011-2017 timeframe and total 34 MW.
   Also included is a 204 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2019

6. No more Capacity Derates for existing units are expected at this time.

7. Buck units 3-4 (113 MW) were retired during the summer of 2011.
   The 824 MW capacity retirement in summer 2012 represents the projected retirement date for Dan River Steam Station units 1-3 (276 MW), Cliffside Steam Station units 1-4 (198 MW), and 350 MWs of old fleet CT retirements.
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

9. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 36 MW.

10-11. A firm wholesale backstand agreement up to 277 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020.

12. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

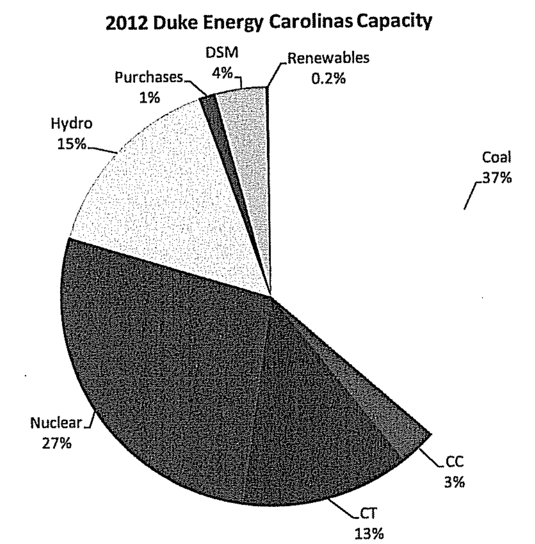
15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

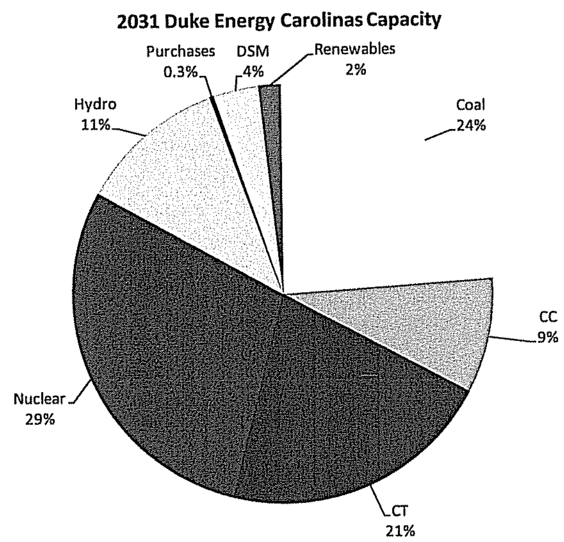
16. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

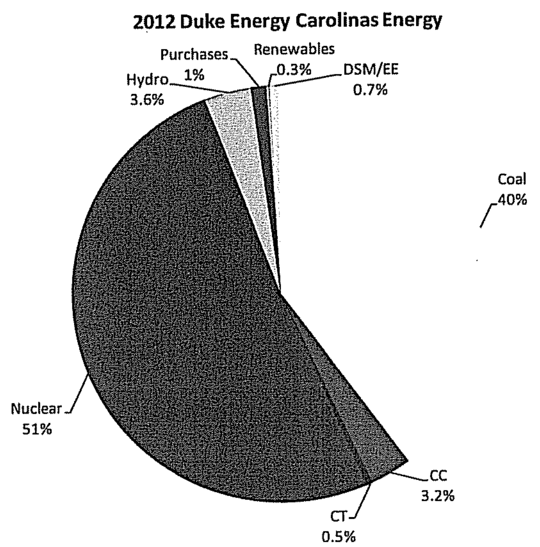
17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

The charts in Chart 8.B and 8.C show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2012 and 2031. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

Chart 8.B







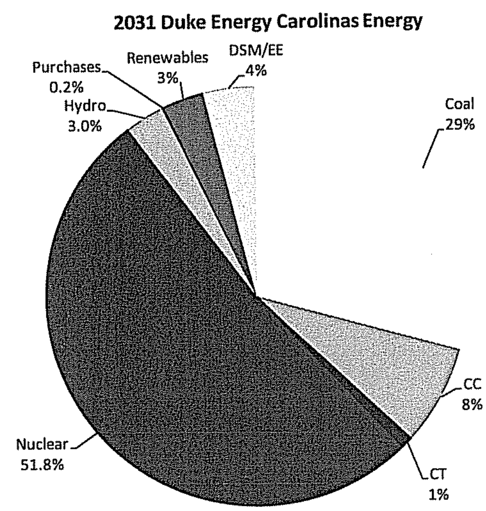
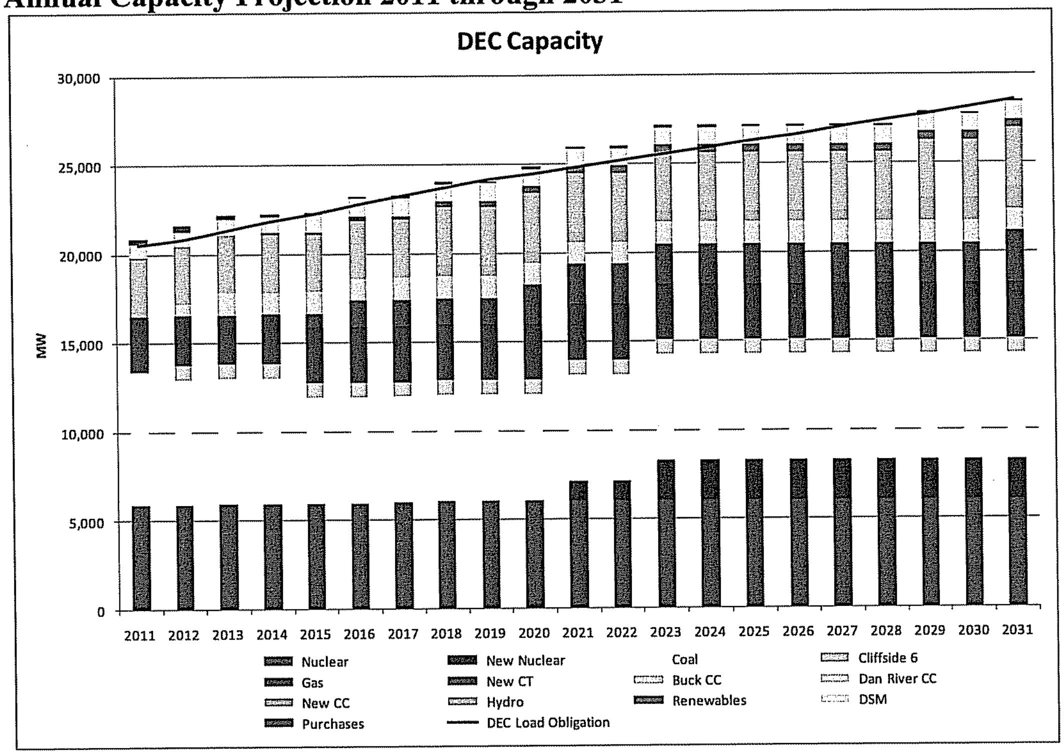


Chart 8.C
Annual Capacity Projection 2011 through 2031



Annual Energy Projection 2011 through 2031

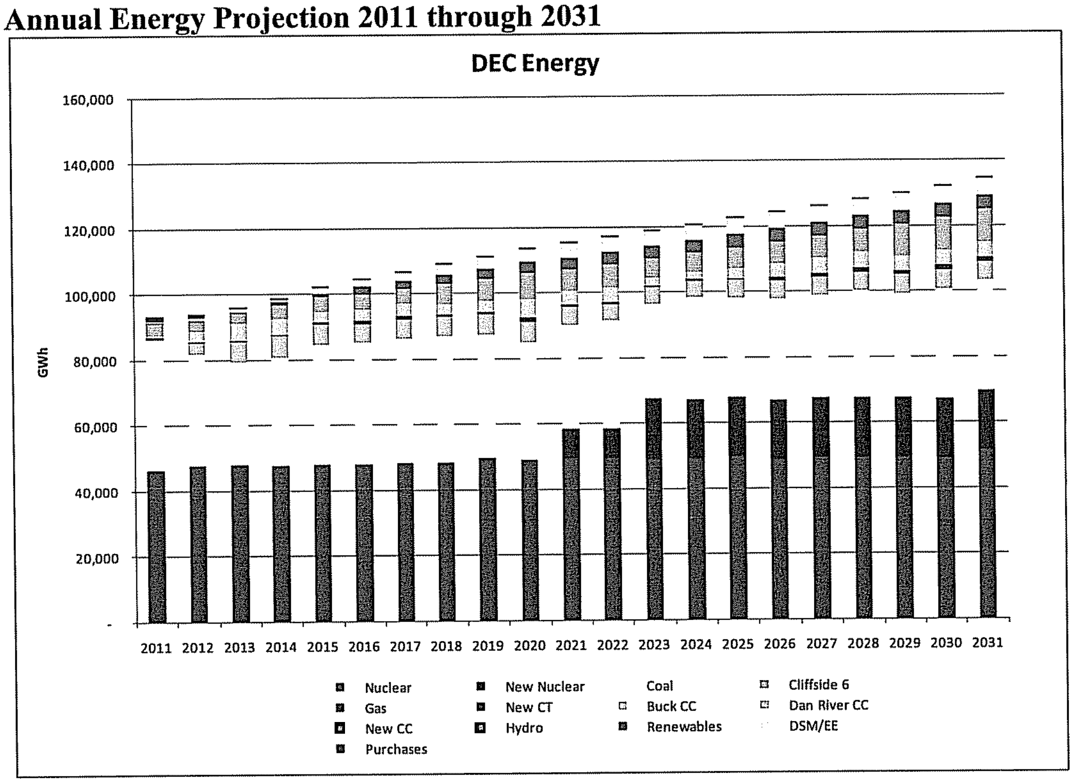


Table 8.D below represents the annual non-renewable incremental additions reflected in the LCR Table of the most robust expansion plan. The plan contains the addition of Cliffside Unit 6 in 2012, the unit retirements shown in Table 5.D and the impact of EE and DSM programs.

Table 8.D

Year	Month	Project	MW
2011	6	Jocassee Uprates	50
2011	12	Buck Combined Cycle	620
2012	6	Cliffside 6	825
2012	6	Bridgewater Hydro	8.75
2012	6	Nuclear Uprates	10
2012	12	Dan River Combined Cycle	620
2013	6	Nuclear Uprates	45
2014	6	Nuclear Uprates	18
2015	6	New CT	740
2016	6	New CT	740
2017	6	Nuclear Uprates	21
2018	6	New CC	650
2018	6	Nuclear Uprates	81
2019	6	Nuclear Uprates	30
2020	6	New CT	740
2021	6	New Nuclear	1117
2023	6	New Nuclear	1117
2029	6	New CC	650
2031	6	New CT	670

The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution of renewable resources towards the Company's peak load needs, are summarized in Table 8.E below.

<u>Table 8.E</u> Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2011	15.0	12	20	46	100	24	20	143
2012	0.0	12	29	41	0	24	29	53
2013	0.0	12	33	44	0	24	33	56
2014	15.0	12	89	116	100	24	89	213
2015	15.6	21	91	128	104	42	91	237
2016	47.8	22	179	249	318	45	179	542
2017	47.8	23	180	250	319	45	180	543
2018	49.7	24	230	304	332	49	230	610
2019	50.7	25	265	341	338	51	265	654
2020	53	28	296	376	352	56	296	703
2021	51	26	295	372	339	51	295	686
2022	55	28	344	427	367	57	344	767
2023	55	36	346	437	368	72	346	786
2024	55	36	347	439	369	73	347	789
2025	58	36	384	478	389	73	384	846
2026	61	41	386	488	406	81	386	874
2027	59	37	385	481	392	73	385	851
2028	59	37	388	484	393	74	388	855
2029	62	41	391	493	411	82	391	884
2030	62	41	391	493	411	82	391	884
2031	62	41	391	493	411	82	391	884

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of resource options available to meet customers' future energy needs.

Overview of Analytical Process

Assess Resource Needs

Duke Energy Carolinas estimates the required load and generation resource balance needed to meet future customer demands by assessing:

- Customer load forecast peak and energy – identifying future customer aggregate demands to identify system peak demands and developing the corresponding energy load shape
- Existing supply-side resources – summarizing each existing generation resource's operating characteristics including unit capability, potential operational constraints, and life expectancy
- Operating parameters – determining operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth coupled with the expiration of purchased power contracts, lower demand response, and renewable compliance assumptions, results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.8% average summer peak system demand growth over the next 20 years without impacts of new energy efficiency programs
- Generation retirements of approximately 350 MW of old fleet combustion turbines by 2012
- Generation retirements of approximately 1,040 MW of older coal units associated with the addition of Cliffside Unit 6.
- Generation retirements of approximately 630 MW of remaining coal units without scrubbers by 2015
- Approximately 70 MW of net generation reductions due to new environmental equipment
- Continued operational reliability of existing generation portfolio
- Using a 17 percent target planning reserve margin for the planning horizon

Identify and Screen Resource Options for Further Consideration

The IRP process evaluates EE, DSM and supply-side options to meet customer energy and capacity needs. The Company develops DSM/EE options for consideration within the IRP based on input from our collaborative partners and cost-effectiveness screening. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable). Supply-side options are initially screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-run reliability
- Reasonable cost parameters.

The Company compared capacity options within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase.

Resource Options

<u>Supply-Side</u>
Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

- Baseload – 800 MW Supercritical Pulverized Coal
- Baseload – 630 MW Integrated Gasification Combined Cycle (IGCC)
- Baseload – 2,234 MW (2x1,117 MW) Nuclear units (AP1000)
- Peaking/Intermediate – 740 MW (4x185 MW) CT
- Peaking/Intermediate – 650 MW (460 MW Unfired + 150MW Duct Fired + 40MW Inlet Chilled) Natural Gas CC
- Renewable – Existing Unit Biomass Co-Firing
- Renewable – Wind PPA On-Shore
- Renewable – Landfill Gas PPA
- Renewable – Solar Photovoltaic PPA
- Renewable – Biomass Firing PPA
- Renewable – Poultry Waste PPA

Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness.

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both demand response and conservation programs in the analysis.

The Company modeled the costs and impacts from EE and DSM programs based on the data included in Duke Energy Carolinas' approved Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831. For the analysis, Duke Energy Carolinas assumed these costs and impacts would continue through the duration of the planning period.

The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Energy Efficiency Plan for 2009 through 2012. The Company assumes for purposes of the IRP that total efficiency savings will continue to grow on an annual basis through 2031, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan.

Develop Theoretical Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This analysis began with a set of basic inputs which were varied to test the system under different future conditions, such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of resources required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The set of basic inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- System operational needs for load ramping, spinning reserve (10 to 15-minute start-up)

- The projected load and generation resource need; and
- A menu of new resource options with corresponding costs and timing parameters.

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, the Company developed a variety of portfolios to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen in order to focus on the optimal timing of CT, CC, and nuclear additions in the 2016 – 2031 timeframe.

The information as shown on the following pages outlines the planning options that the Company considered in the portfolio analysis phase. Each portfolio contains demand response and conservation identified in the base EE and DSM case and renewable portfolio standard requirements modeled after the NC REPS in NC and applied to SC. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck CC in 2012 and Dan River CC in 2013 and the unit retirements shown in Table 5 D.

The RPS assumptions are based on NC REPS in North Carolina. The assumptions for planning purposes are as follows:

Overall Requirements/Timing

- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

Additional Requirements

- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with out-of-state, unbundled RECs
- Solar requirement
    - 0.02% by 2010
    - 0.07% by 2012

    - 0.14% by 2015
    - 0.20% by 2018
- Hog waste requirement (NC only – using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018
- Poultry waste requirement (NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 71,400 MWh by 2012
    - 294,000 MWh by 2013
    - 378,000 MWh by 2014

The overall requirements were applied to all retail load and to wholesale customers who have contracted with Duke Energy Carolinas to meet their REPS requirement. The requirement that a certain percentage must come from Hog and Poultry waste was not applied to the South Carolina portion.

Conduct Portfolio Analysis

Duke Energy Carolinas tested the portfolio options under the nominal set of inputs, as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

For this IRP analysis, the Company selected six main scenarios to illustrate the impacts of key risks and decisions. Three of these scenarios fall into the Reference CO_2 Case and three fall into the Clean Energy Legislation Case.

- Reference Case: Cap and trade program with CO_2 prices based on Duke Energy's 2011 fundamental prices.
- Clean Energy Legislation: In addition to evaluating potential CO_2 cap and trade options, the impact of proposed Clean Energy legislation without a price on CO_2 emissions was also evaluated. Assumptions used in this analysis include:
    - 10% of retail sales by 2015 must be clean energy, increasing to 30% by 2030.
    - Alternative Compliance Payment (ACP) of 50$/MWhr.
    - "Clean Energy" includes renewable resources, EE, nuclear, natural gas CC, or alternative compliance payment.
    - Portfolios based on this legislation include the increased EE to meet 25

percent of the total clean energy target.

The six analyzed portfolios are shown below:

Reference CO_2 Case Scenarios:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. Lee Nuclear – Two Lee Nuclear unit portfolio with units on-line in 2021 and 2023 (2N 2021-2023)
3. Regional Nuclear – Co-ownership of nuclear units in the region. The portfolio consists of 215 MW of nuclear in 2018, 730 MW in 2021 and 2023, and 559 MW in 2028 (Reg Nuclear)

Clean Energy Legislation Scenarios:

4. Clean Energy CC – CC portfolio with the Clean Energy Legislation assumptions
5. Clean Energy 2N – Two Lee Nuclear unit portfolio with the Clean Energy Legislation assumptions
6. Clean Energy Regional Nuclear – Regional co-ownership of nuclear with the Clean Energy Legislation assumptions

An overview of the specifics of each portfolio is shown in Table A.1 below.

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward.

The Company evaluated the following sensitivities in the Reference CO_2 Case scenarios:

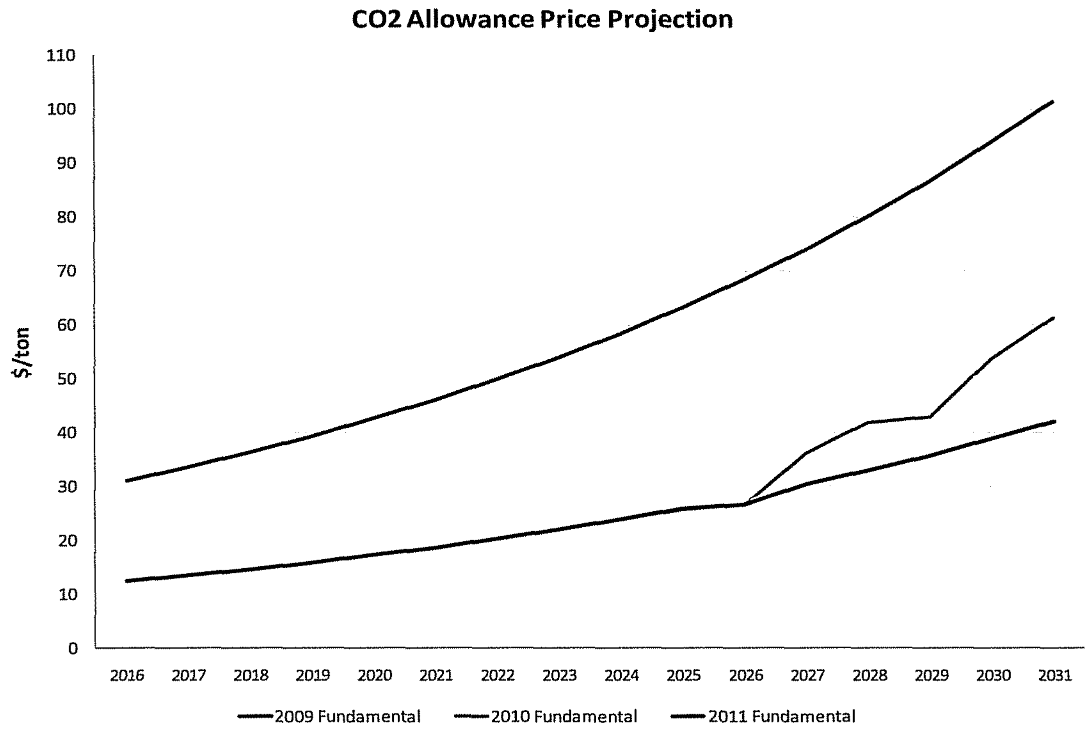
- Load forecast variations
  - Increase relative to base forecast (+15% for peak demand and +16% for energy by 2031)
  - Decrease relative to base forecast (-8% for peak demand and energy by 2031)
- Construction cost sensitivity[5]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 25% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 40% lower)

[5] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

- Nuclear Financing
  - Federal loan guarantees for the Lee nuclear station
- The Carbon reference case had CO_2 emission prices ranging from \$12/ton starting in 2016 to \$42/ton in 2031. The Company performed sensitivities based on the 2009 and 2010 fundamental CO_2 prices.
- High Energy Efficiency – This sensitivity includes the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented, this increased EE impacts resulted in approximately a 13% decrease in retail sales over the planning period.

Chart A.1 shows the CO_2 prices utilized in the analysis.

Chart A.1



For the Clean Energy Legislation, the Company also performed a sensitivity by lowering the ACP to \$30/MWhr and increasing the renewable energy assumptions to lower the Company's need to purchase ACPs.

An overview of the specifics of each portfolio is shown in Table A.1 below.

Table A.1 – Portfolios Evaluated

Year	Portfolios					
	CT/CC	2N 2021/2023	Regional Nuclear	Clean Energy Std - Gas	Clean Energy Std - Nuc	Clean Energy Std - Reg Nuc
2011						
2012						
2013						
2014						
2015	CT	CT	CT	CC	CT	CT
2016	CT	CT	CT	CC	CT	CT
2017						
2018	CC	CC	N	CC	CC	N
2019			CC	CC		CC
2020	CT	CT			CC	
2021		N	N		N	N
2022				CC		
2023	CC	N	N		N	N
2024				CC		
2025	CC		CT			
2026	CT			CC		CC
2027			CC			
2028	CC		N	CC		N
2029		CC				
2030	CC			CC	CT	CT
2031	CT	CT	CT	CC	CT	CT
Total CT	3,180 MW	2,890 MW	2,890 MW		2,450 MW	2,450 MW
Total CC	3,250 MW	1,300 MW	1,300 MW	6,000 MW	1,300 MW	1,300 MW
Total Nuclear		2,234 MW	2,234 MW		2,234 MW	2,234 MW
Total Nuclear Uprate	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW
Total Retire	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW

Quantitative Analysis Results

The quantitative analysis focused on critical variables that impact the need for and timing of new nuclear generation. Three potential resource planning strategies were tested under base assumption and variations in CO_2 price, fuel costs, load/energy efficiency, and nuclear capital costs. These three potential resource planning strategies are:

- No new nuclear capacity (the CT/CC portfolio)

- Full ownership of new nuclear capacity (the 2 Nuclear Units portfolio)
- Regional co-ownership of new nuclear capacity (the Regional Nuclear portfolio)

For the base case and sensitivities, the Company calculated the PVRR for each portfolio. The revenue requirement calculation estimates the costs to customers for the Company to recover system production costs and new capital incurred. Duke Energy Carolinas used a 50-year analysis time frame to fully capture the long-term impact of nuclear generation added late in the 20 year planning horizon. Table A2 below represents a comparison of the Natural Gas (CT/CC) portfolio with a full ownership nuclear portfolio (1st unit in 2021 & 2nd unit in 2023) and the regional nuclear portfolio over a range of sensitivities. The green block represents the lowest PVRRs between the Natural Gas and the two nuclear portfolios. The value contained within the block is the PVRR savings in $billions between the cases.

Table A.2

Comparison of Nuclear Portfolios to the CT/CC Portfolio

(Cost are represented in $billions)

	Reference Case	**CO2 Price Sensitivity**		**Fuel Sensitivity**	
Portfolio		2009 Fundamental	2010 Fundamental	High Fuel Cost	Low Fuel Cost
2 Nuclear Units (2021-2023)	(0.6)	(5.9)	(2.0)	(2.8)	
Regional Nuclear	(1.1)	(6.1)	(2.4)	(3.2)	
Natural Gas					(3.0) 2N / (2.4) Reg

	Load Sensitivity			**Nuclear Capital Cost Sensitivity**	
	High Load	Low Load	High DSM	20% Increase	10% Decrease
2 Nuclear Units (2021-2023)	(1.0)	(0.6)	(0.4)		(1.8)
Regional Nuclear	(1.3)	(0.9)	(0.7)		(2.2)
Natural Gas				(1.8) 2N / (1.2) Reg	

	Nuclear Financing		**Clean Energy Bill**	
Portfolio	FLG	Portfolio	$50 ACP	$30 ACP
2 Nuclear Units (2021-2023)	(1.0)	2 Nuclear Units (2021-2023)	(2.6)	(1.2)
Regional Nuclear	(1.3)	Regional Nuclear	(2.9)	(1.6)
Natural Gas		Natural Gas		

Based on the quantitative analysis, the optimal plan includes two new nuclear units in the 2020 timeframe. The nuclear portfolios resulted in a lower cost to customers in every case with the exception of increased nuclear capital cost and lower fuel cost. In a Clean Energy Standard regulatory construct, the advantages of adding additional nuclear are greater than in a CO_2 Cap and Trade construct.

The Company's proposed portfolio including full ownership of two nuclear units in 2021 and 2023 continues to be cost effective, but the Company recognizes the potential benefits to customers of securing new nuclear generation in smaller capacity increments through regional nuclear development. The analysis indicates that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2011 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Regional nuclear is where two or more partners plan collaboratively to stage multiple nuclear stations over a period of years and each partner would own a portion of each station. Several advantages to a regional nuclear approach are:

- Load Growth: Smaller blocks of base load generation brought on-line over a period of years would more closely match projected load growth.
- Financial: The substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases.
- Regulatory Uncertainty: The optimal amount and timing of additional nuclear generation will depend on the outcome of final legislation. Using a regional approach would allow utilities to better optimize their portfolios as legislation or regulation change over time.

Duke Energy Carolinas strongly supports this concept and continues to explore regional nuclear opportunities. The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources. Recent efforts in support of regional nuclear include:

- In February 2011, JEA (formerly Jacksonville Electric Authority), located in Jacksonville, Florida, signed an option to potentially purchase up to 20% of Lee Nuclear Station.

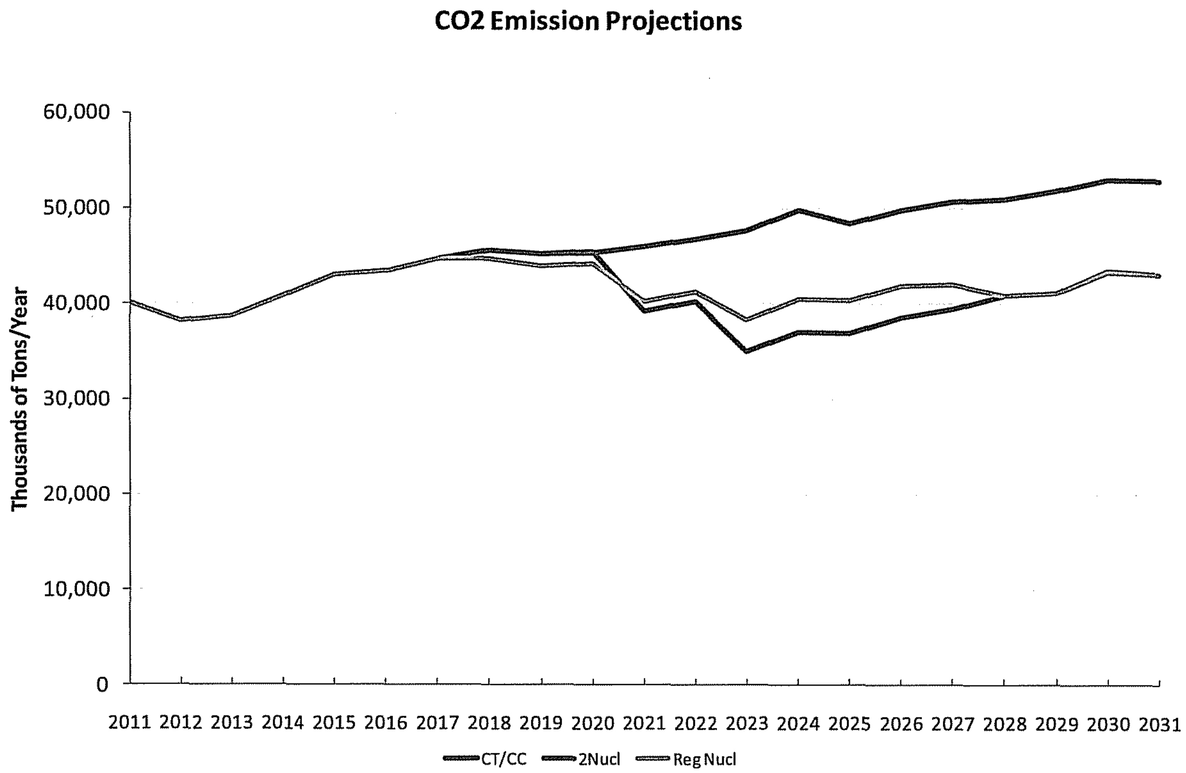
- In July 2011, the Company signed a letter of intent with Santee Cooper to perform due diligence and potentially acquire an option for a minority interest (5 to 10 percent of the capacity of the two units) in Santee Cooper's 45 percent ownership of the planned new nuclear reactors at V.C. Summer Nuclear Generating Station in South Carolina. The new units are scheduled to be online between 2016 and

2019.

Quantitative Analysis Summary

One of the major benefits of having additional nuclear generation is the lower system CO_2 footprint and the associated economic benefit. The projected CO_2 emissions under the CT/CC, 2 Nuclear, and Regional Nuclear scenarios are shown in Chart A.4 below. A review of these projections illustrates that for the Company to achieve material system reductions in CO_2 emissions, it must add new nuclear generation to the future resource portfolio.

Chart A.3



The biggest risks to the proposed nuclear portfolios are the time required to license and construct a nuclear unit, uncertainty regarding GHG regulation/legislation, potential for lower demand than currently estimated, capital cost to build, and the ability to secure favorable financing. However, in a carbon constrained future, new nuclear generation must be in the generation mix to reduce the Company's carbon footprint.

In summary, the results of the quantitative analyses indicate that it is prudent for Duke Energy Carolinas to continue to preserve the option to build new nuclear capacity in the 2020 timeframe. The Company's analysis re-affirms the advantages of favorable financing and co-ownership in future nuclear generation. Duke Energy Carolinas is aggressively pursuing favorable financing options and continues to seek potential co-owners for this generation.

The overall conclusions of the quantitative analysis are that significant additions of baseload, intermediate, peaking, EE, DSM, and renewable resources to the Duke Energy Carolinas portfolio are required over the planning horizon. Conclusions based on these analyses are:

- The new levels of EE and DSM are cost-effective for customers.
    - The screening analysis shows that portfolios with the new EE and DSM were lower cost than those without and EE and DSM.
    - The high EE sensitivity assumes 100% participation of cost effective EE programs identified in the market potential study. The high EE sensitivity is cost effective if there is an equal participation between residential and non-residential customers. If a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective.
- Significant renewable resources will be needed to meet the new NC REPS (and potentially a federal standard).
- There is a capacity need in 2015 to 2020 timeframe to maintain the 17% reserve margin.
- The analysis demonstrates that the nuclear option is an attractive option for the Company's customers.
    - Continuing to preserve the option to secure new nuclear generation is prudent under the circumstances.
    - Favorable financing is very important to the project cost when compared to other generation options.
    - Co-ownership is beneficial from a generation and risk perspective.

For the purpose of demonstrating that there will be sufficient resources to meet customers' needs, Duke Energy Carolinas has selected a portfolio which, over the 20-year planning horizon provides for the following:

- 987 MW equivalent of incremental capacity under the new save-a-watt DSM programs
- 727 MW of new EE (reduction to system peak load)

- 2,234 MW of new nuclear capacity
- 1,300 MW of new CC capacity
- 2,890 MW of new CT capacity
- 204 MW of nuclear uprates
- 484 MW of renewables (858 MWs nameplate)

Significant challenges remain with respect to the Company's portfolio, such as obtaining the necessary regulatory approvals to implement the EE and DSM programs and supply side resources, finding sufficient cost-effective, reliable renewable resources to meet the NC REPS standard, effectively integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources.

APPENDIX B

Duke Energy Carolinas Spring 2011 Forecast

Duke Energy.

Sales

Rates Billed

Peaks

2011-2026

August 17, 2011

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Regular Sales and System Peak Summer (2010 Forecast vs. 2011 Forecast)

Regular sales include total Retail and Full/Partial Requirements Wholesale sales. The system peak summer demand includes all MW demands associated with the IRP loads. The table below shows values after the effects of utility sponsored energy efficiency have been reflected.

Growth Statistics from 2011 to 2012				
	Forecasted 2011	**Forecasted 2012**	**Growth**	
Item	**Amount**	**Amount**	**Amount**	**%**
Regular Sales	81,008 GWH	82,273 GWH	1,266 GWH	1.6%
System Peak Summer	17,557 MW	17,812 MW	255 MW	1.5%

Regular Sales Outlook for the Forecast Horizon (2010 – 2026)

Total Regular sales for the Spring 2011 Forecast are projected to grow at an average annual rate of 1.5% from 2010 through 2026, the same rate as the Fall 2010 Forecast. The Spring 2011 Forecast for Residential and Commercial is higher in the short and mid-term due to higher economic growth and a smaller reduction in the expected impacts of CFL's. In the long-run, however, the Residential and Commercial forecasts are slightly lower due to higher energy efficiency impacts The Industrial Forecast is higher throughout due to stronger economic projections in industries such autos and steel, and a surprisingly improved textile outlook. Adjustments were made to the energy forecasts for the Spring 2011 Forecast and the Fall 2010 Forecast to account for utility sponsored efficiency programs. The expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007 was reflected differently in the Spring 2011 Forecast. Its impacts were reflected directly in the residential model rather than an ex-post adjustment. Additional adjustments to the Spring 2011 Forecast include sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) beginning in 2011.

The Full/Partial Requirements Wholesale class forecast will increase due to new sales contracts with Central Electric Power Cooperative, Inc. (CEPCI) starting in 2013.

(Load Forecast Pg 1)

Comparison of Regular Sales Growth Statistics Spring 2011 Forecast vs. Fall 2010 Forecast					
	Spring 2011 Forecast Annual Growth (2010-2026)		Fall 2010 Forecast Annual Growth (2010-2026)		Average Annual Difference [1]
Item	Amount	%	Amount	%	
Regular Sales:					
Residential	272 GWH	0.9%	289 GWH	0.9%	-16 GWH
Commercial	569 GWH	1.8%	595 GWH	1.8%	-26 GWH
Industrial (total)	158 GWH	0.7%	96 GWH	0.5%	62 GWH
Textile	-35 GWH	-0.9%	-64 GWH	-1.8%	29 GWH
Other Industrial	193 GWH	1.1%	160 GWH	0.9%	33 GWH
Other [2]	5 GWH	1.5%	5 GWH	1.6%	0 GWH
Full/Partial Wholesale [3]	377 GWH	5.0%	390 GWH	5.1%	-13 GWH
Total Regular	1,381 GWH	1.5%	1,375 GWH	1.5%	6 GWH

[1] *Average annual differences may not match due to rounding*
[2] *Other sales consist of Street and Public Lighting and Traffic Signal GWH sales.*
[3] *For List of Full/Partial Wholesale customers see page 6..*

System Peak Outlook for the Forecast Horizon (2010 – 2026)

System peak demands are forecasted on a summer and winter basis. Additional adjustments have been made to the Spring 2011 Forecast for the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) and utility sponsored enery efficiency programs. The system peak summer demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.8% from 2010 through 2026. The system peak winter demand is expected to grow at an average annual rate of 1.7% from 2010 through 2026.

Comparison of System Peak Demand Growth Statistics Spring 2011 Forecast vs. Fall 2010 Forecast					
	Spring 2011 Forecast Annual Growth (2010-2026)		Fall 2010 Forecast Annual Growth (2010-2026)		Average Annual Difference [1]
Item	Amount	%	Amount	%	
System Peaks					
Summer	353 MW	1.8%	333 MW	1.7%	19 MW
Winter	316 MW	1.7%	296 MW	1.6%	20 MW

(Load Forecast pg 2)

Other Forecasts

- The number of rates billed is forecasted for the Residential, Commercial and Industrial classes of Duke Energy Carolinas. The total number of rates billed is expected to grow at 1.3% annually over the forecast horizon.

(Load Forecast pg 3)

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2010

Duke Energy Carolinas' Spring 2011 forecasts represent projections of the energy and peak demand needs for its service area, which is located within the states of North and South Carolina, including the major urban areas of Charlotte, Greensboro and Winston-Salem in North Carolina and Spartanburg and Greenville in South Carolina. The forecasts cover the time period of 2011 – 2026 and represent the energy and peak demand needs for the Duke Energy Carolinas system comprised of the following customer classes and other utility/wholesale entities:

- Residential
- Commercial
- Textiles
- Other Industrial
- Other Retail
- Duke Energy Carolinas full /partial requirements wholesale

Energy use is dependent upon key economic factors such as income, energy prices and employment along with weather. The general framework of the Company's forecast methodology begins with projections of regional economic activity, demographic trends and expected long-term weather. The economic projections used in the Spring 2011 forecasts are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Duke Carolinas service area region. These economic forecasts represent long-term projections of numerous economic concepts including the following:

- Total real gross regional product (GRP)
- Non-manufacturing real GRP
- Non-manufacturing employment
- Manufacturing real GRP industry group, e.g., textiles
- Manufacturing Employment by industry group
- Total real personal income

Total population forecasts are obtained from the two states' demographic offices for each county in each state which are then used to derive the total population forecast for the 51 counties that the Company serves in the Carolinas.

(Load Forecast pg 4)

General forecasting methodology (continued)

A projection of weather variables, cooling degree days (CDD) and heating degree days (HDD), are made for the forecast period by examining long-term historical weather. For the Spring 2011 forecasts, a 10 year simple average of CDD and HDD from 2001-2010 was used.

Other factors influencing the forecasts are identified and quantified such as changes in wholesale power contracts and housing trends, which reflects the Energy Information Administration's outlook for appliance saturations and efficiency trends.

The price of electricity is also an important input to the energy and peak models. The projected price of electricity is developed by the company's Financial Model group, and incorporates expected future costs of captial additions, fuel price increases, as well as enviromental costs, such as tighter Carbon standards.

Energy forecasts for all of the Company's retail customers are developed at a customer class level, i.e., residential, commercial, textile, other industrial and street lighting along with forecasts for its wholesale customers. Econometric models incorporating the use of industry-standard linear regression techniques were developed utilizing a number of key drivers of energy usage as outlined above. The following provides information about the models.

Residential Class:
The Company's residential class sales forecast is comprised of two separate and independent forecasts. The first is the number of residential rates billed which is driven by population projections of the counties in which the Company provides electric service. The second forecast is energy usage per rate billed which is driven primarily by weather, regional economic trends, electric price and appliance efficiencies. The total residential sales forecast is derived by multiplying the two forecasts together.

Commercial Class:
Commercial electricity usage changes with the level of regional economic activity and the impact of weather.

Textile Class:
The level of electricity consumption by Duke Energy Carolinas' textile group is impacted by the level of textile manufacturing output, exchange rates, electric prices and weather.

Other Industrial Class:
Electricity usage for Duke's other industrial customers was forecasted by 14 groups according to the 3 digit NAICS classification and then aggregated to provide the overall other industrial sales forecast. Usage is driven primarily by regional manufacturing output at a 3 digit NAICS level, electric prices and weather.

Other Retail Class:
This class in comprised of public street lighting and traffic signals within the Company's service area. The level of electricity usage is impacted not only by economic growth but

General forecasting methodology (continued)

Wholesale:
Duke Energy Carolnas serves the follwing wholesale customers on a full or partial basis:

Concord, Prosperity, Dallas, Lockhart, Forest City, Greenwood, Kings Mountain, Highlands, Due West, Western Carolina, Blue Ridge EMC, Piedmont EMC, New River, Rutherford EMC, Central, and NCEMC Fixed Load Shape.

The larger wholesale entities, Blue Ridge, Rutherford, and Piedmont, are forecasted by econometric models. The smaller whoelsale customers, however, are projected by using an assumed growth rate, comparable to Duke Carolinas Retail growth.

Peaks:
Adjustments were made to the energy and peak projections for the Spring 2011 Forecast to reflect additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable.

Similarly, Duke Energy Carolinas' forecasts of its annual summer and winter peak demand forecasts uses econometric linear regression models that relate historical annual summer/winter peak demands to key drivers including daily temperature variables (such as daily sum of heating degree hours from 7 to 8AM in the winter with a base of 60 degrees and the daily sum of cooling degree hours from 1 to 5PM in the summer with a base of 69 degrees) and the monthly electricity usage of the entity to be forecasted.

(Load Forecast Pg 6)

Billed Sales and Other Energy Requirements

(Load Forecast Pg 7)

Regular Sales, which includes billed sales to Retail and Full/Partial Requirements Wholesale classes, are expected to grow at 1381 GWH per year or 1.5% over the forecast horizon. Retail sales include GWH sales billed to the Residential, Commercial, Industrial, Street and Public Lighting, and Traffic Signal Service classes. Wholesale sales are to resale customers that Duke provides either full or partial service.

Adjustments were made to the energy and peak projections for the Spring 2011 Forecast to reflect additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable.

Points of Interest

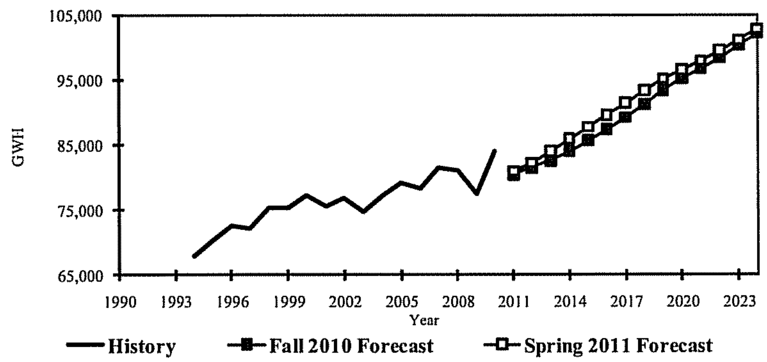
• The **Residential** class continues to show positive growth, driven by steady gains in population within the Duke Energy Carolinas service area. The resulting annual growth in Residential billed sales is expected to average 1.4% over the forecast horizon on a temperature corrected basis..

• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 1.8% per year over the next fifteen years. The three largest sectors in the Commercial Class are Offices, which includes banking, Retail and Education.

• The **Industrial** class rebounded strongly in 2010 after struggling for several years. The long term structural decline that has occurred in the Textile industry is expected to moderate significantly in the forecast horizon, with an overall projected decline of 0.9%. In the Other Industrial sector, several industries such as Autos, Rubber & Plastics and Primary Metals, are projected to show strong growth. Overall, Other Industrial sales are expected to grow 1.1% over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 5.0% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina and sales to CEPCI in South Carolina.

Regular Billed Sales *(Sum of Retail and Full/Partial Wholesale classes)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2001	75,605	-1,692	-2.2
2002	76,769	1,164	1.5
2003	74,784	-1,984	-2.6
2004	77,374	2,590	3.5
2005	79,130	1,756	2.3
2006	78,347	-784	-1.0
2007	81,572	3,225	4.1
2008	81,066	-505	-0.6
2009	77,528	-3,538	-4.4
2010	84,088	6,560	8.5

AVERAGE ANNUAL GROWTH

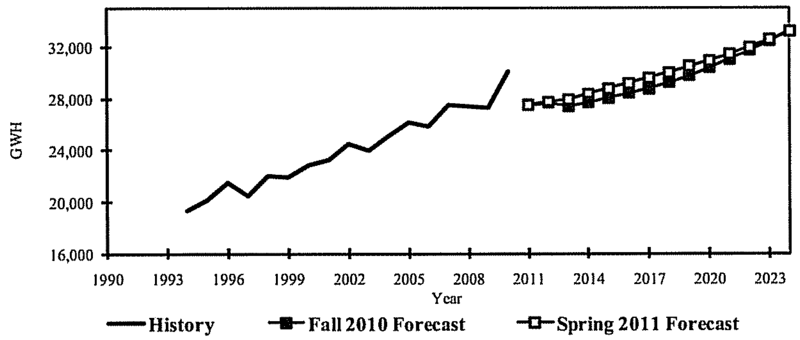
	GWH Per Year	% Per Year
History (2005 to 2010)	992	1.2
History (1995 to 2010)	918	1.2
Spring 2011 Forecast (2010 to 2026)	1381	1.5
Fall 2010 Forecast (2010 to 2026)	1375	1.5

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Spring 2011 GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	81,008	-3,081	-3.7	80,519	489	0.6	-3,570
2012	82,273	1,266	1.6	81,543	730	0.9	1,025
2013	84,039	1,766	2.1	82,577	1,462	1.8	1,034
2014	85,930	1,891	2.2	84,041	1,890	2.2	1,463
2015	87,752	1,821	2.1	85,715	2,037	2.4	1,674
2016	89,570	1,819	2.1	87,393	2,178	2.5	1,678
2017	91,427	1,857	2.1	89,235	2,192	2.5	1,843
2018	93,364	1,937	2.1	91,248	2,115	2.3	2,013
2019	95,146	1,782	1.9	93,415	1,731	1.9	2,167
2020	96,546	1,399	1.5	95,166	1,380	1.4	1,751
2021	97,950	1,405	1.5	96,687	1,263	1.3	1,521
2022	99,479	1,529	1.6	98,432	1,047	1.1	1,745
2023	101,104	1,625	1.6	100,294	810	0.8	1,862
2024	102,775	1,670	1.7	102,224	551	0.5	1,930
2025	104,454	1,679	1.6	104,107	347	0.3	1,883
2026	106,189	1,734	1.7	106,094	94	0.1	1,987

(Load Forecast Pg 9)

Residential Billed Sales



HISTORY | **AVERAGE ANNUAL GROWTH**

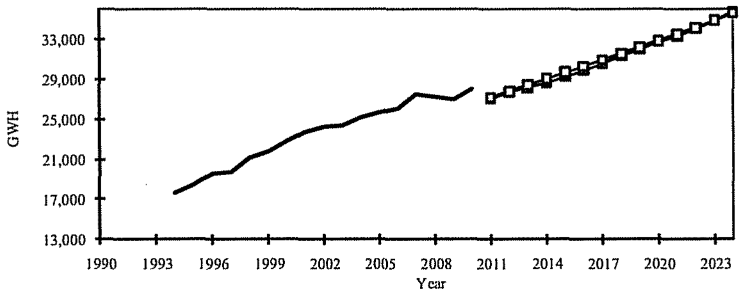
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	23,272	388	1.7			
2002	24,466	1,194	5.1			
2003	23,947	-519	-2.1			
2004	25,150	1,203	5.0			
2005	26,108	958	3.8			
2006	25,816	-292	-1.1	History (2005 to 2010)	788	2.9
2007	27,459	1,643	6.4	History (1995 to 2010)	662	2.7
2008	27,335	-124	-0.5			
2009	27,273	-62	-0.2	Spring 2011 Forecast (2010 to 2026)	272	0.9
2010	30,049	2,777	10.2	Fall 2010 Forecast (2010 to 2026)	289	0.9

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	27,517	-2,532	-8.4	27,464	53	0.2	-2,585
2012	27,749	232	0.8	27,656	93	0.3	192
2013	27,914	165	0.6	27,400	514	1.9	-255
2014	28,350	436	1.6	27,663	687	2.5	262
2015	28,760	410	1.4	28,036	724	2.6	373
2016	29,154	394	1.4	28,367	787	2.8	331
2017	29,554	400	1.4	28,743	811	2.8	376
2018	29,995	441	1.5	29,201	794	2.7	458
2019	30,454	459	1.5	29,732	722	2.4	531
2020	30,926	472	1.5	30,315	612	2.0	582
2021	31,387	461	1.5	31,008	379	1.2	693
2022	31,946	559	1.8	31,698	248	0.8	691
2023	32,535	589	1.8	32,434	101	0.3	736
2024	33,154	619	1.9	33,204	-50	-0.1	770
2025	33,774	620	1.9	33,896	-122	-0.4	692
2026	34,408	634	1.9	34,668	-260	-0.7	772

(Load Forecast Pg 10)

Commercial Billed Sales

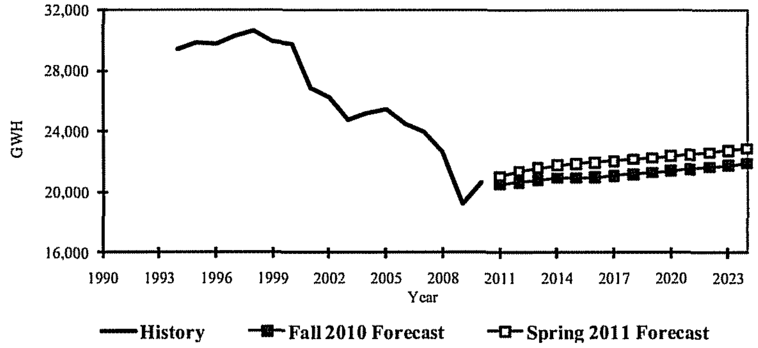


HISTORY				AVERAGE ANNUAL GROWTH		
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	23,666	821	3.6			
2002	24,242	576	2.4			
2003	24,355	113	0.5			
2004	25,204	849	3.5			
2005	25,679	475	1.9			
2006	26,030	352	1.4	History (2005 to 2010)	458	1.7
2007	27,433	1,402	5.4	History (1995 to 2010)	634	2.8
2008	27,288	-145	-0.5			
2009	26,977	-311	-1.1	Spring 2011 Forecast (2010 to 2026)	569	1.8
2010	27,968	991	3.7	Fall 2010 Forecast (2010 to 2026)	595	1.8

SPRING 2011 FORECAST				Fall 2010 FORECAST			
Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	27,148	-820	-2.9	27,076	72	0.3	-892
2012	27,759	611	2.3	27,688	72	0.3	612
2013	28,399	640	2.3	28,146	253	0.9	458
2014	29,031	631	2.2	28,588	443	1.5	442
2015	29,658	627	2.2	29,229	429	1.5	641
2016	30,281	623	2.1	29,903	378	1.3	674
2017	30,907	626	2.1	30,571	336	1.1	668
2018	31,537	630	2.0	31,301	236	0.8	730
2019	32,173	636	2.0	32,020	153	0.5	719
2020	32,815	642	2.0	32,760	54	0.2	741
2021	33,468	653	2.0	33,295	173	0.5	535
2022	34,129	662	2.0	34,040	89	0.3	745
2023	34,847	718	2.1	34,862	-15	0.0	822
2024	35,577	729	2.1	35,710	-133	-0.4	847
2025	36,319	742	2.1	36,598	-279	-0.8	888
2026	37,074	756	2.1	37,494	-420	-1.1	896

(Load Forecast Pg 11)

Total Industrial Billed Sales *(includes Textile and Other Industrial)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2001	26,902	-2,869	-9.6
2002	26,259	-643	-2.4
2003	24,764	-1,496	-5.7
2004	25,209	445	1.8
2005	25,495	286	1.1
2006	24,535	-960	-3.8
2007	23,948	-587	-2.4
2008	22,634	-1,314	-5.5
2009	19,204	-3,430	-15.2
2010	20,618	1,414	7.4

AVERAGE ANNUAL GROWTH

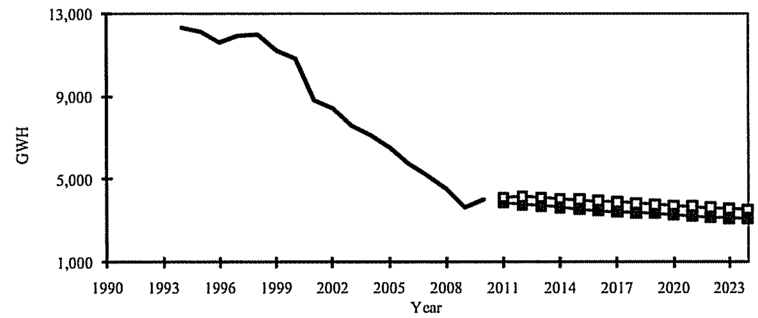
	GWH Per Year	% Per Year
History (2005 to 2010)	-975	-4.2
History (1995 to 2010)	-618	-2.4
Spring 2011 Forecast (2010 to 2026)	158	0.7
Fall 2010 Forecast (2010 to 2026)	96	0.5

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	21,026	408	2.0	20,515	511	2.5	-103
2012	21,374	348	1.7	20,664	711	3.4	149
2013	21,600	225	1.1	20,812	787	3.8	149
2014	21,770	171	0.8	20,951	819	3.9	139
2015	21,871	100	0.5	20,944	927	4.4	-7
2016	21,963	93	0.4	20,982	981	4.7	38
2017	22,059	96	0.4	21,082	977	4.6	100
2018	22,159	100	0.5	21,178	981	4.6	96
2019	22,263	104	0.5	21,294	969	4.6	116
2020	22,375	112	0.5	21,404	970	4.5	111
2021	22,493	119	0.5	21,525	969	4.5	120
2022	22,618	125	0.6	21,653	966	4.5	128
2023	22,748	130	0.6	21,777	972	4.5	124
2024	22,876	128	0.6	21,901	975	4.5	124
2025	23,001	125	0.5	22,025	976	4.4	124
2026	23,147	146	0.6	22,161	987	4.5	136

(Load Forecast Pg 12)

Textile Billed Sales



HISTORY | **AVERAGE ANNUAL GROWTH**

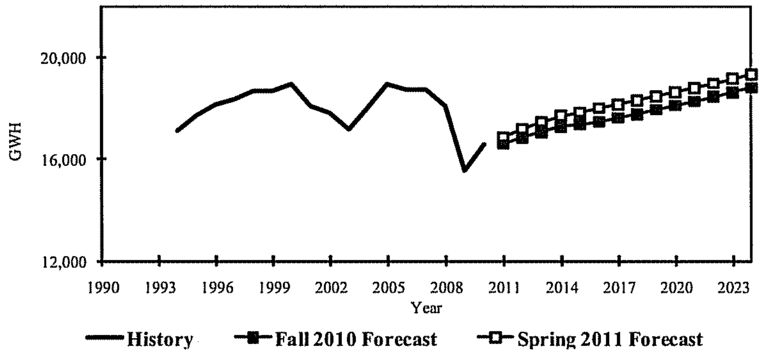
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	8,825	-1,989	-18.4			
2002	8,443	-382	-4.3			
2003	7,562	-881	-10.4			
2004	7,147	-415	-5.5			
2005	6,561	-586	-8.2			
2006	5,791	-770	-11.7	History (2005 to 2010)	-512	-9.4
2007	5,224	-567	-9.8	History (1995 to 2010)	-543	-7.1
2008	4,524	-700	-13.4			
2009	3,616	-908	-20.1	Spring 2011 Forecast (2010 to 2026)	-35	-0.9
2010	4,003	387	10.7	Fall 2010 Forecast (2010 to 2026)	-64	-1.8

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	4,134	131	3.3	3,872	261	6.8	-130
2012	4,159	25	0.6	3,788	371	9.8	-84
2013	4,125	-33	-0.8	3,723	403	10.8	-66
2014	4,068	-57	-1.4	3,656	412	11.3	-66
2015	4,011	-57	-1.4	3,560	451	12.7	-96
2016	3,953	-57	-1.4	3,499	454	13.0	-60
2017	3,900	-54	-1.4	3,445	455	13.2	-55
2018	3,845	-54	-1.4	3,390	455	13.4	-55
2019	3,790	-55	-1.4	3,339	451	13.5	-51
2020	3,739	-51	-1.3	3,286	453	13.8	-53
2021	3,689	-51	-1.4	3,235	453	14.0	-51
2022	3,638	-51	-1.4	3,184	454	14.2	-51
2023	3,588	-50	-1.4	3,131	457	14.6	-53
2024	3,539	-49	-1.4	3,078	460	15.0	-52
2025	3,491	-48	-1.4	3,028	463	15.3	-50
2026	3,445	-45	-1.3	2,979	466	15.7	-49

(Load Forecast Pg 13)

Other Industrial Billed Sales



HISTORY

Year	Actual GWH	GWH	Growth %
2001	18,077	-880	-4.6
2002	17,816	-261	-1.4
2003	17,202	-614	-3.4
2004	18,063	861	5.0
2005	18,934	872	4.8
2006	18,744	-191	-1.0
2007	18,724	-20	-0.1
2008	18,110	-614	-3.3
2009	15,588	-2,522	-13.9
2010	16,616	1,028	6.6

AVERAGE ANNUAL GROWTH

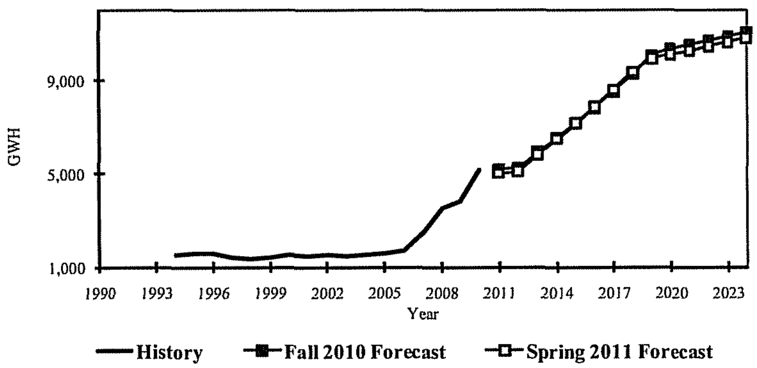
	GWH Per Year	% Per Year
History (2005 to 2010)	-464	-2.6
History (1995 to 2010)	-75	-0.4
Spring 2011 Forecast (2010 to 2026)	193	1.1
Fall 2010 Forecast (2010 to 2026)	160	0.9

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	16,893	277	1.7	16,643	250	1.5	27
2012	17,216	323	1.9	16,876	340	2.0	233
2013	17,474	259	1.5	17,090	385	2.3	214
2014	17,702	228	1.3	17,295	407	2.4	205
2015	17,860	158	0.9	17,384	476	2.7	89
2016	18,010	150	0.8	17,483	527	3.0	99
2017	18,159	150	0.8	17,637	522	3.0	154
2018	18,314	154	0.8	17,788	526	3.0	151
2019	18,473	159	0.9	17,955	518	2.9	167
2020	18,635	162	0.9	18,118	517	2.9	163
2021	18,805	169	0.9	18,289	515	2.8	171
2022	18,981	176	0.9	18,469	512	2.8	179
2023	19,160	180	0.9	18,646	515	2.8	177
2024	19,337	177	0.9	18,822	515	2.7	177
2025	19,510	173	0.9	18,997	514	2.7	174
2026	19,702	192	1.0	19,182	520	2.7	185

(Load Forecast Pg 14)

Full / Partial Requirements Wholesale Billed Sales [1]



HISTORY				AVERAGE ANNUAL GROWTH		
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	1,484	-16	-1.1			
2002	1,530	47	3.1			
2003	1,448	-82	-5.4			
2004	1,542	93	6.4			
2005	1,580	38	2.5			
2006	1,694	114	7.2	History (2005 to 2010)	717	26.7
2007	2,454	760	44.8	History (1995 to 2010)	238	8.1
2008	3,525	1,072	43.7			
2009	3,788	262	7.4	Spring 2011 Forecast (2010 to 2026)	377	5.0
2010	5,166	1,379	36.4	Fall 2010 Forecast (2010 to 2026)	390	5.1

SPRING 2011 FORECAST				Fall 2010 FORECAST			
		Growth			SPRING 2011 vs. FALL 2010		Fall 2010 Growth
Year	GWH	GWH	%	GWH	GWH	%	Per Year
2011	5,027	-139	-2.7	5,172	-145	-2.8	6
2012	5,098	71	1.4	5,239	-141	-2.7	67
2013	5,829	731	14.3	5,917	-88	-1.5	678
2014	6,478	648	11.1	6,532	-55	-0.8	615
2015	7,157	679	10.5	7,194	-37	-0.5	662
2016	7,862	705	9.8	7,823	38	0.5	629
2017	8,592	730	9.3	8,518	74	0.9	694
2018	9,353	761	8.9	9,241	112	1.2	724
2019	9,932	579	6.2	10,037	-106	-1.1	796
2020	10,101	169	1.7	10,349	-248	-2.4	311
2021	10,268	168	1.7	10,517	-249	-2.4	168
2022	10,446	177	1.7	10,693	-247	-2.3	176
2023	10,628	182	1.7	10,868	-240	-2.2	175
2024	10,816	188	1.8	11,051	-235	-2.1	183
2025	11,002	186	1.7	11,224	-222	-2.0	173
2026	11,195	192	1.7	11,402	-208	-1.8	178

1 Schedule 10A Resale Sales does not include SEPA allocation.

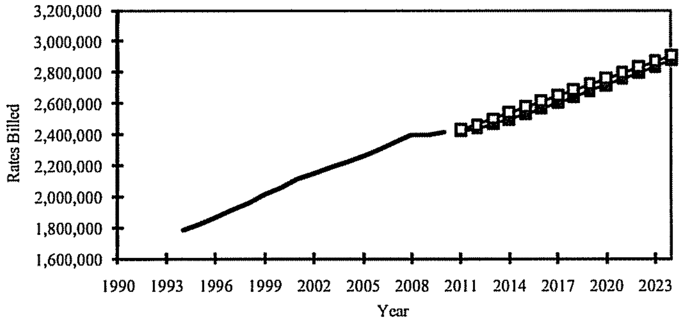
(Load Forecast Pg 15)

Number of Rates Billed

(Load Forecast Pg 16)

Total Rates Billed

(Sum of Major Retail Classes: Residential, Commercial and Industrial)



HISTORY / AVERAGE ANNUAL GROWTH

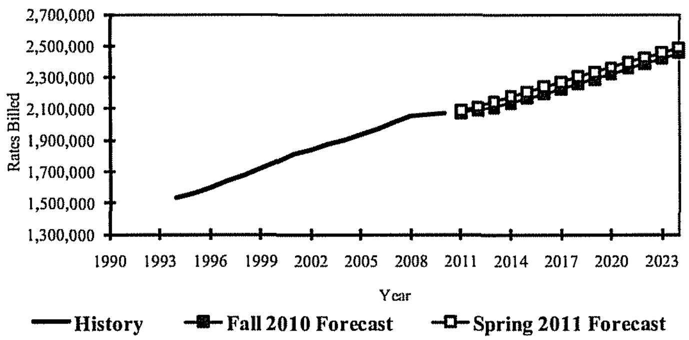
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	2,117,432	58,280	2.8			
2002	2,148,117	30,685	1.4			
2003	2,186,825	38,708	1.8			
2004	2,221,590	34,766	1.6			
2005	2,261,639	40,049	1.8			
2006	2,304,050	42,411	1.9	History (2005 to 2010)	30,289	1.3
2007	2,354,078	50,028	2.2	History (1995 to 2010)	39,573	1.9
2008	2,393,426	39,348	1.7			
2009	2,399,359	5,933	0.2	Spring 2011 Forecast (2010 to 2026)	35,490	1.3
2010	2,413,085	13,727	0.6	Fall 2010 Forecast (2010 to 2026)	34,098	1.3

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	2,432,796	19,711	0.8	2,419,493	13,303	0.5	6,408
2012	2,461,853	29,057	1.2	2,441,122	20,731	0.8	21,629
2013	2,500,751	38,899	1.6	2,467,355	33,396	1.4	26,233
2014	2,539,624	38,872	1.6	2,498,353	41,271	1.7	30,997
2015	2,577,453	37,829	1.5	2,532,562	44,891	1.8	34,210
2016	2,614,490	37,037	1.4	2,567,517	46,973	1.8	34,955
2017	2,651,397	36,907	1.4	2,605,027	46,370	1.8	37,510
2018	2,688,220	36,823	1.4	2,642,592	45,629	1.7	37,565
2019	2,724,824	36,604	1.4	2,680,067	44,757	1.7	37,475
2020	2,761,410	36,586	1.3	2,718,487	42,923	1.6	38,420
2021	2,798,003	36,593	1.3	2,757,932	40,070	1.5	39,445
2022	2,834,602	36,599	1.3	2,797,858	36,743	1.3	39,926
2023	2,871,206	36,604	1.3	2,837,010	34,196	1.2	39,151
2024	2,907,812	36,606	1.3	2,876,261	31,551	1.1	39,251
2025	2,944,418	36,606	1.3	2,917,108	27,310	0.9	40,847
2026	2,980,922	36,504	1.2	2,958,661	22,261	0.8	41,553

(Load Forecast Pg 17)

Residential Rates Billed



HISTORY / AVERAGE ANNUAL GROWTH

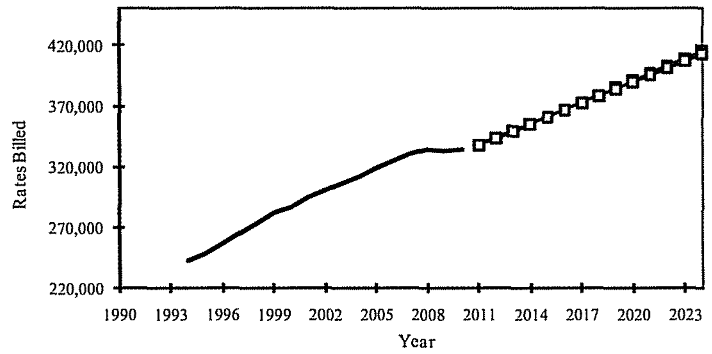
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	1,813,867	49,684	2.8			
2002	1,839,689	25,822	1.4			
2003	1,872,484	32,795	1.8			
2004	1,901,335	28,851	1.5			
2005	1,935,320	33,985	1.8			
2006	1,971,673	36,353	1.9	History (2005 to 2010)	27,311	1.4
2007	2,016,104	44,431	2.3	History (1995 to 2010)	33,990	1.9
2008	2,052,252	36,149	1.8			
2009	2,059,394	7,142	0.3	Spring 2011 Forecast (2010 to 2026)	29,890	1.3
2010	2,071,877	12,484	0.6	Fall 2010 Forecast (2010 to 2026)	28,311	1.2

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%		Fall 2010 Growth Per Year
2011	2,087,805	15,928	0.8	2,074,790	13,016	0.6		2,913
2012	2,111,339	23,534	1.1	2,090,384	20,955	1.0	0.8%	15,594
2013	2,144,532	33,193	1.6	2,110,803	33,729	1.6	1.0%	20,419
2014	2,177,288	32,756	1.5	2,136,238	41,051	1.9	1.2%	25,434
2015	2,209,204	31,915	1.5	2,164,770	44,433	2.1	1.3%	28,533
2016	2,240,467	31,263	1.4	2,193,961	46,505	2.1	1.3%	29,191
2017	2,271,658	31,192	1.4	2,225,590	46,068	2.1	1.4%	31,628
2018	2,302,781	31,122	1.4	2,257,247	45,533	2.0	1.4%	31,658
2019	2,333,700	30,919	1.3	2,288,808	44,892	2.0	1.4%	31,560
2020	2,364,617	30,918	1.3	2,321,292	43,325	1.9	1.4%	32,484
2021	2,395,539	30,922	1.3	2,354,751	40,788	1.7	1.4%	33,459
2022	2,426,465	30,925	1.3	2,388,605	37,860	1.6	1.4%	33,854
2023	2,457,395	30,931	1.3	2,421,649	35,747	1.5	1.4%	33,044
2024	2,488,332	30,937	1.3	2,454,772	33,559	1.4	1.4%	33,124
2025	2,519,270	30,939	1.2	2,489,476	29,794	1.2	1.4%	34,704
2026	2,550,110	30,840	1.2	2,524,854	25,256	1.0	1.4%	35,378

(Load Forecast Pg 18)

Commercial Rates Billed



HISTORY / AVERAGE ANNUAL GROWTH

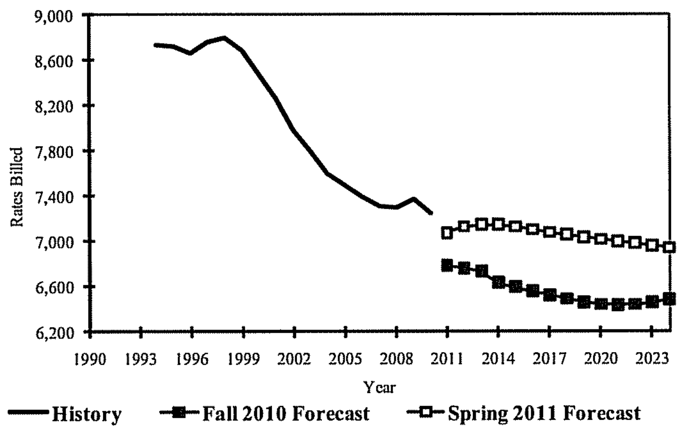
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	295,300	8,805	3.1			
2002	300,440	5,140	1.7			
2003	306,540	6,101	2.0			
2004	312,665	6,125	2.0			
2005	318,827	6,162	2.0			
2006	324,977	6,150	1.9	History (2005 to 2010)	3,027	0.9
2007	330,666	5,689	1.8	History (1995 to 2010)	5,681	2.0
2008	333,873	3,208	1.0			
2009	332,593	-1,280	-0.4	Spring 2011 Forecast (2010 to 2026)	5,622	1.5
2010	333,960	1,367	0.4	Fall 2010 Forecast (2010 to 2026)	5,831	1.6

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%	Fall 2010 Growth Per Year
2011	337,918	3,958	1.2	337,920	-2	0.0	3,960
2012	343,384	5,466	1.6	343,977	-593	-0.2	6,057
2013	349,077	5,693	1.7	349,819	-742	-0.2	5,842
2014	355,189	6,112	1.8	355,484	-295	-0.1	5,666
2015	361,123	5,934	1.7	361,197	-73	0.0	5,713
2016	366,919	5,795	1.6	366,998	-80	0.0	5,801
2017	372,660	5,741	1.6	372,916	-256	-0.1	5,917
2018	378,382	5,722	1.5	378,856	-474	-0.1	5,941
2019	384,087	5,705	1.5	384,800	-713	-0.2	5,944
2020	389,777	5,690	1.5	390,755	-979	-0.3	5,955
2021	395,466	5,690	1.5	396,748	-1,281	-0.3	5,992
2022	401,157	5,690	1.4	402,814	-1,657	-0.4	6,066
2023	406,848	5,691	1.4	408,904	-2,057	-0.5	6,090
2024	412,539	5,692	1.4	415,002	-2,463	-0.6	6,098
2025	418,232	5,693	1.4	421,113	-2,881	-0.7	6,111
2026	423,917	5,685	1.4	427,255	-3,338	-0.8	6,142

(Load Forecast Pg 19)

Total Industrial Rates Billed *(Includes Textile and Other Industrial)*



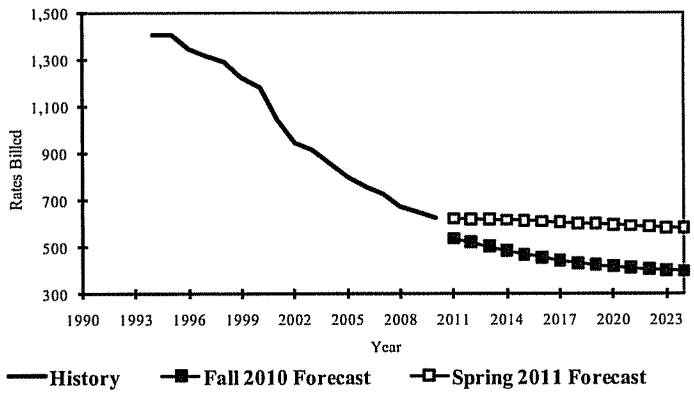
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	8,265	-210	-2.5			
2002	7,989	-276	-3.3			
2003	7,801	-188	-2.3			
2004	7,591	-210	-2.7			
2005	7,492	-99	-1.3			
2006	7,401	-91	-1.2	History (2005 to 2010)	-49	-0.7
2007	7,309	-92	-1.2	History (1995 to 2010)	-98	-1.2
2008	7,301	-8	-0.1			
2009	7,372	71	1.0	Spring 2011 Forecast (2010 to 2026)	-22	-0.3
2010	7,248	-124	-1.7	Fall 2010 Forecast (2010 to 2026)	-44	-0.6

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	7,073	-175	-2.4	6,783	289	4.3	-465
2012	7,130	57	0.8	6,761	368	5.4	-22
2013	7,143	13	0.2	6,733	409	6.1	-28
2014	7,146	3	0.0	6,631	515	7.8	-102
2015	7,126	-20	-0.3	6,595	531	8.0	-36
2016	7,104	-22	-0.3	6,557	547	8.3	-38
2017	7,079	-26	-0.4	6,522	557	8.5	-36
2018	7,057	-21	-0.3	6,488	569	8.8	-34
2019	7,037	-20	-0.3	6,459	578	8.9	-29
2020	7,016	-21	-0.3	6,440	576	8.9	-19
2021	6,997	-19	-0.3	6,434	564	8.8	-6
2022	6,981	-17	-0.2	6,440	541	8.4	6
2023	6,963	-18	-0.3	6,457	506	7.8	17
2024	6,941	-22	-0.3	6,486	455	7.0	29
2025	6,915	-26	-0.4	6,519	397	6.1	33
2026	6,894	-22	-0.3	6,551	343	5.2	32

Textile Rates Billed



HISTORY | **AVERAGE ANNUAL GROWTH**

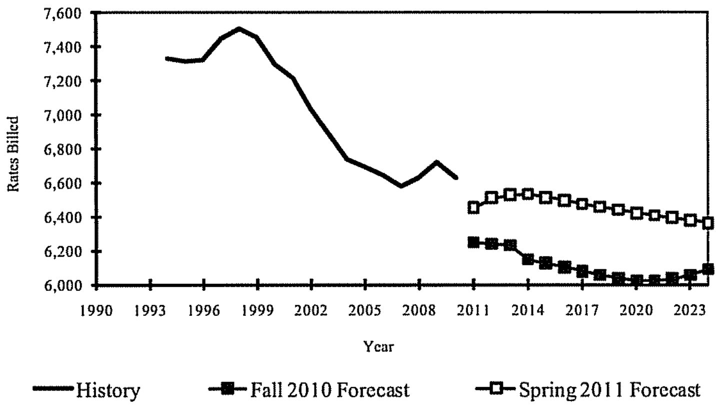
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	1,052	-129	-10.9			
2002	949	-103	-9.8			
2003	914	-35	-3.6			
2004	857	-57	-6.2			
2005	802	-56	-6.5			
2006	757	-45	-5.6	History (2005 to 2010)	-36	-4.9
2007	728	-29	-3.8	History (1995 to 2010)	-52	-5.3
2008	675	-53	-7.3			
2009	649	-26	-3.9	Spring 2011 Forecast (2010 to 2026)	-3	-0.5
2010	622	-27	-4.2	Fall 2010 Forecast (2010 to 2026)	-14	-2.9

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%	Fall 2010 Growth Per Year
2011	623	1	0.1	536	86	16.1	-86
2012	621	-2	-0.3	522	99	19.0	-15
2013	618	-2	-0.4	503	115	22.8	-18
2014	616	-2	-0.4	485	131	27.1	-19
2015	613	-3	-0.5	469	144	30.7	-16
2016	609	-4	-0.6	455	154	33.8	-14
2017	606	-3	-0.6	443	163	36.8	-12
2018	602	-3	-0.6	432	170	39.3	-11
2019	599	-4	-0.6	424	175	41.4	-9
2020	595	-3	-0.6	417	178	42.7	-7
2021	592	-3	-0.6	412	180	43.8	-5
2022	588	-4	-0.6	407	182	44.7	-5
2023	585	-4	-0.7	402	183	45.5	-5
2024	581	-4	-0.7	398	182	45.8	-3
2025	576	-5	-0.8	395	181	45.9	-3
2026	573	-3	-0.6	391	182	46.5	-4

(Load Forecast Pg 21)

Other Industrial Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
2001	7,213	-81	-1.1
2002	7,040	-173	-2.4
2003	6,887	-153	-2.2
2004	6,733	-154	-2.2
2005	6,690	-43	-0.6
2006	6,644	-47	-0.7
2007	6,581	-63	-0.9
2008	6,626	45	0.7
2009	6,723	97	1.5
2010	6,626	-97	-1.4

AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2005 to 2010)	-13	-0.2
History (1995 to 2010)	-46	-0.7
Spring 2011 Forecast (2010 to 2026)	-19	-0.3
Fall 2010 Forecast (2010 to 2026)	-29	-0.5

SPRING 2011 FORECAST / **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	6,450	-176	-2.7	6,247	203	3.2	-379
2012	6,509	59	0.9	6,240	269	4.3	-8
2013	6,524	15	0.2	6,230	294	4.7	-10
2014	6,530	6	0.1	6,146	384	6.2	-84
2015	6,513	-17	-0.3	6,126	387	6.3	-20
2016	6,495	-18	-0.3	6,102	393	6.4	-24
2017	6,473	-22	-0.3	6,079	394	6.5	-23
2018	6,455	-18	-0.3	6,056	399	6.6	-23
2019	6,438	-17	-0.3	6,036	403	6.7	-20
2020	6,420	-18	-0.3	6,023	398	6.6	-13
2021	6,405	-15	-0.2	6,022	383	6.4	-1
2022	6,392	-13	-0.2	6,033	359	5.9	11
2023	6,378	-14	-0.2	6,055	323	5.3	22
2024	6,360	-18	-0.3	6,088	273	4.5	32
2025	6,339	-21	-0.3	6,124	216	3.5	36
2026	6,321	-18	-0.3	6,160	161	2.6	36

System Peaks

(Load Forecast Pg 23)

Summer Peak

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes as well as wholesale customers to whom Duke provides full or partial service. It represents the Integrated Resource Plan load that Duke is obligated to serve. It is expressed in MW at the point of generation and includes losses.

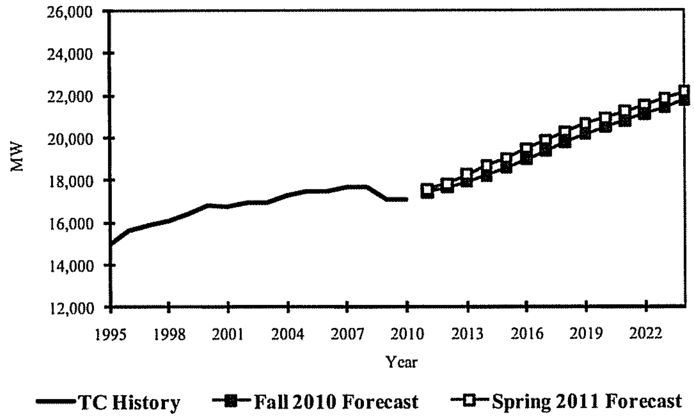
Adjustments were made to the peak forecast associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. Adjustments were also made to reflect the impacts of utility sponsored energy efficiency programs.

Growth Forecasts

The new forecast projects an incremental growth of 345 MW or 1.7% per year for 2011-2026. The previous forecast growth was 334 MW or 1.7% per year for 2011-2026.

(Load Forecast Pg 24)

System Summer MW (IRP Load)



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
2001	16,748	-79	-0.5
2002	16,919	171	1.0
2003	16,915	-4	0.0
2004	17,285	370	2.2
2005	17,497	212	1.2
2006	17,439	-58	-0.3
2007	17,698	259	1.5
2008	17,670	-28	-0.2
2009	17,100	-570	-3.2
2010	17,088	-12	-0.1

AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2005 to 2010)	-82	-0.5
History (1995 to 2010)	140	0.9
Spring 2011 Forecast (2010 to 2026)	353	1.8
Fall 2010 Forecast (2010 to 2026)	333	1.7

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Spring 2011 MW	Growth MW	Growth %	Fall 2010 MW	SPRING 2011 vs. FALL 2010 MW	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	17,557	469	2.7	17,418	139	0.8	330
2012	17,812	255	1.5	17,659	153	0.9	241
2013	18,245	433	2.4	17,893	352	2.0	234
2014	18,680	435	2.4	18,216	464	2.5	323
2015	19,032	352	1.9	18,582	450	2.4	366
2016	19,476	444	2.3	18,983	493	2.6	401
2017	19,877	401	2.1	19,372	505	2.6	389
2018	20,265	388	2.0	19,790	475	2.4	418
2019	20,644	379	1.9	20,172	472	2.3	382
2020	20,901	257	1.2	20,498	403	2.0	326
2021	21,214	313	1.5	20,788	426	2.0	290
2022	21,530	316	1.5	21,101	429	2.0	313
2023	21,836	306	1.4	21,425	411	1.9	324
2024	22,135	299	1.4	21,759	376	1.7	334
2025	22,465	330	1.5	22,085	380	1.7	326
2026	22,733	268	1.2	22,423	310	1.4	338

(Load Forecast Pg 25)

Winter Peak

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes as well as wholesale customers to whom Duke provides full or partial service. It represents the Integrated Resource Plan load that Duke is obligated to serve. It is expressed in MW at the point of generation and includes losses.

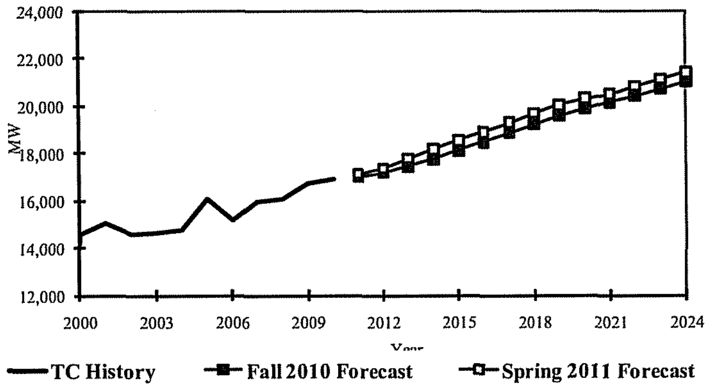
Adjustments were made to the peak forecast associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. Adjustments were also made to reflect the impacts of utility sponsored energy efficiency programs.

Growth Forecasts

The new Forecast projects an incremental growth of 323 MW or 1.7% per year from 2011-2026. The previous forecast growth was 308 MW or 1.6% per year from 2011-2026.

(Load Forecast Pg 26)

System Winter MW



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
2001	15,071	486	3.3
2002	14,565	-506	-3.4
2003	14,626	61	0.4
2004	14,770	144	1.0
2005	16,054	1,285	8.7
2006	15,193	-861	-5.4
2007	15,936	742	4.9
2008	16,065	130	0.8
2009	16,723	657	4.1
2010	16,893	170	1.0

AVERAGE ANNUAL GROWTH

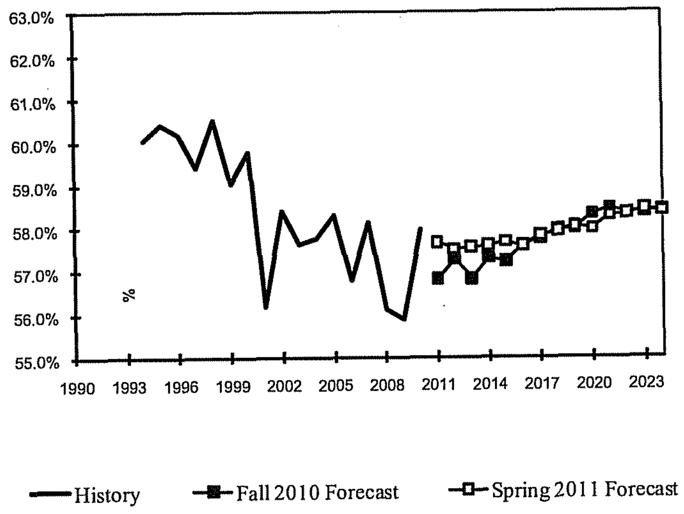
	MW Per Year	% Per Year
History (2005 to 2010)	168	1.0
History (2000 to 2010)	231	1.5
Spring 2011 Forecast (2010 to 2026)	316	1.7
Fall 2010 Forecast (2010 to 2026)	296	1.6

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Spring 2011 MW	Growth MW	Growth %	Fall 2010 MW	SPRING 2011 vs. FALL 2010 MW	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	17,115	222	1.3	17,004	111	0.7	111
2012	17,359	243	1.4	17,204	155	0.9	200
2013	17,773	414	2.4	17,455	318	1.8	251
2014	18,177	404	2.3	17,767	410	2.3	312
2015	18,543	366	2.0	18,111	432	2.4	344
2016	18,891	348	1.9	18,485	406	2.2	374
2017	19,305	414	2.2	18,848	457	2.4	363
2018	19,694	388	2.0	19,234	460	2.4	386
2019	20,042	348	1.8	19,582	460	2.4	348
2020	20,304	262	1.3	19,873	431	2.2	291
2021	20,492	188	0.9	20,150	342	1.7	277
2022	20,835	343	1.7	20,434	401	2.0	284
2023	21,124	288	1.4	20,729	395	1.9	295
2024	21,412	288	1.4	21,028	384	1.8	299
2025	21,697	285	1.3	21,326	371	1.7	298
2026	21,956	259	1.2	21,631	325	1.5	305

(Load Forecast Pg 27)

The system load factor represents the relationship between annual energy and the maximum demand for the Duke Energy Carolinas' system. It is measured at generation level and excludes off-system sales and peaks.



Load Factor

(Load Forecast Pg 28)

APPENDIX C: SUPPLY-SIDE SCREENING

The following sets of estimated Levelized Busbar Cost[6] charts provide an economic comparison of the technologies in their respective categories. Busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[7]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis. The Renewables Busbar Chart shows a single point for each type of resource at the particular capacity factor specified. Also, the capacity (MW size) of the Baseload and Peak/Intermediate technology categories are listed in the chart legends, and tabular listings below. The expected energy (MWh) at any given capacity factor (whether along a continuous line, or a specific point) may be determined by the following formula: Expected Energy (MWh) = 8,760 x Capacity (MW size) x Capacity Factor (%/100).

Busbar Charts by Technology Category – Base 2011 Fundamentals Carbon Scenario

Baseload

The following technologies are found on the baseload technologies screening chart:

1) 2 x 1,117 MW Nuclear
2) 800 MW Supercritical Coal
3) 800 MW Supercritical Coal with Carbon Capture and Storage at 90%
4) 630 MW IGCC Coal
5) 630 MW IGCC with Carbon Capture and Storage at 90%

[6] While these estimated levelized busbar costs provide a reasonable basis for initial screening of technologies, simple busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies within the context of Duke Energy Carolinas' existing generation portfolio.

[7] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 50% of installed capacity at the time of peak.

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Baseload Technologies Screening 2011-2031

[redacted]

2 x 1117 MW Nuclear w/o Sunk Costs (AP1000)
800 MW Supercritical Coal - Greenfield
630 MW Class IGCC Greenfield
630 MW w/CCS 90% IGCC
800 MW w/CCS 90% SCPC

New un-sequestered coal generation is the lowest cost baseload option. However, baseload coal was not considered in the detailed portfolio evaluation due to EPA's pursuit of GHG regulation on new and existing coal units.

Nuclear becomes economic compared to IGCC at about 60% capacity factor. It is important to note that the capital and operating costs for carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological sequestration of CO_2 once it is captured. The sequestration geology is not favorable in the Carolinas.

Intermediate and Peaking

The following technologies are found on the peak/intermediate technologies screening chart:

1) 4x204 MW Simple-Cycle CT
2) 460 MW Unfired + 150 MW Duct Fired + 40 MW Inlet Evaporative Cooler Combined Cycle (650MW total)
3) 460 MW Unfired + 40 MW Inlet Evaporative Cooler Combined Cycle (500 MW total)

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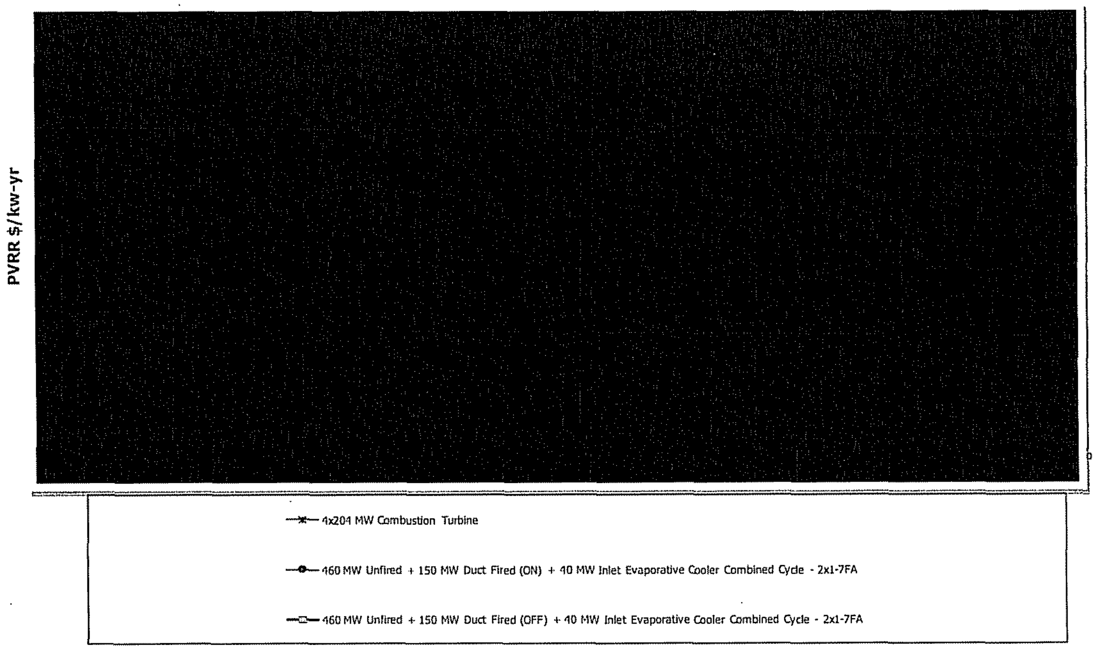
Peak / Intermediate Technologies Screening 2011-2031



The simple-cycle CT unit makes up the lower envelope of the curves up to about 35% capacity factor, where the unfired option is the most economic over the rest of the capacity factor range.

Duct firing in a CC unit is a process to introduce more fuel (heat) directly into the combustion turbine exhaust (waste heat) stream, by way of a duct burner, to increase the temperature of the exhaust gases entering the Heat Recovery Steam Generator (HRSG). This additional heat allows the production of additional steam to produce more electricity in the steam (bottoming) cycle of a CC unit. It is a low cost ($/kW installed cost) way to increase power (MW) output during times of very high electrical demands and/or system emergencies. However, it adversely impacts the efficiency (raises the heat rate) and thereby dramatically increases the operating cost of a CC unit (notice the much steeper slope of the duct firing "On" cases in the screening curve charts). Duct firing also increases emissions, generally resulting in a very limited number of hours per year that duct firing is allowed within operating permits.

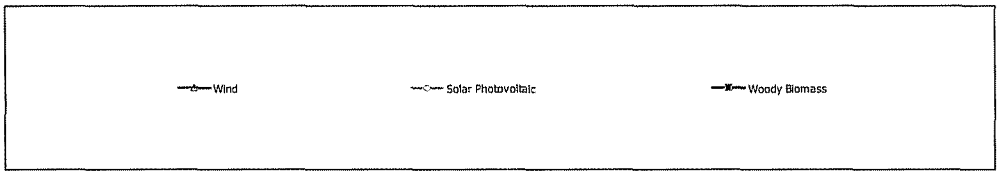
Within the screening curves, the estimated capital cost for a combined cycle unit always includes the duct burner and related equipment. The two curves, one "On," and one "Off," are intended to show the efficiency loss (steeper slope) when the duct burner is "On", but also show that even with the duct burner "On" the efficiency (slope) is still better than a simple-cycle CT unit (much steeper slope). The duct burner "Off" curve is where the combined cycle unit will operate most of the time, and this is the one best compared with all other candidate technologies

Renewables

The following technologies are found on the renewable technologies screening chart:

1) 150 MW Wind
2) 25 MW Solar Photovoltaic
3) 100 MW Woody Biomass

[redacted]



One must remember that busbar charts comparisons involving some renewable resources, particularly wind and solar resources can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[8]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis.

Since these renewable technologies either have no CO_2 emissions or are deemed to be carbon neutral, the cost of CO_2 emissions does not impact their operating cost. Wind appears to be the least cost renewable alternative through its maximum practical capacity

[8] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 50% of installed capacity at the time of peak.

factor range. Woody biomass is next throughout its entire capacity range. The Solar Photovoltaic is the most costly renewable within the renewable category.

APPENDIX D: DEMAND SIDE MANAGEMENT ACTIVATION HISTORY

DEMAND-SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
09/10-06/11	Air Conditioners	Economic Event	113 MW	Verifying	06/21/2011
	Standby Generator	Emergency Event	48 MW	54 MW	06/01/2011
		Monthly Tests			
	Interruptible Service	Emergency Event	145 MW	147 MW	06/01/2011
		Communication Test	N/A	N/A	05/12/2011
	PowerShare Generator	Emergency Event	11 MW	8 MW	06/01/2011
	PowerShare Mandatory	Emergency Event	280 MW	325 MW	06/01/2011
	PowerShare Voluntary	Economic Event	N/A	14 MW	12/15/2010
		Economic Event	N/A	1 MW	06/01/2011
		Economic Event	N/A	16 MW	06/02/2011
	PowerShare CallOption	Economic Event	0.2 MW	0.2 MW	12/14/2010
		Economic Event	0.2 MW	0.2 MW	12/15/2010
		Economic Event	0.2 MW	0.2 MW	01/13/2011
9/09 – 9/10*	Air Conditioners	Economic Event	46 MW**	50 MW	6/14/2010
		Economic Event	50 MW	45 MW	6/15/2010
		Economic Event	103 MW**	102 MW	6/23/2010
		Economic Event	90 MW	81 MW	07/07/2010
		Economic Event	90 MW	87 MW	07/08/2010
		Economic Event	99 MW	103 MW	07/22/2010
		Economic Event	114 MW	114 MW	07/23/2010
		Economic Event	107 MW	107 MW	08/05/2010
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	6/8/2010
	PowerShare Voluntary	Economic Event	N/A	13 MW	6/15/2010
		Economic Event	N/A	17 MW	6/23/2010
		Economic Event	N/A	9 MW	7/7/2010
		Economic Event	N/A	7 MW	7/8/2010
		Economic Event	N/A	7 MW	7/23/2010
		Economic Event	N/A	28 MW	7/29/2010
		Economic Event	N/A	5 MW	8/4/2010
		Economic Event	N/A	7 MW	8/5/2010
	PowerShareCallOption	Economic Event	0.2 MW	0.2 MW	07/07/2010
		Economic Event	0.2 MW	0.2 MW	07/08/2010
		Economic Event	0.2 MW	0.2 MW	08/05/2010
9/08 -9/09	Air Conditioners	Cycling Event		30 MW	8/10/2009
		SOC Full Shed Test	N/A	N/A	8/11/2009
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2009

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/07 – 9/08	Air Conditioners				
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2008
8/06 – 8/07	Air Conditioners	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	120 MW	88 MW	8/2/2007
	Water Heaters	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	2 MW	Included in Air Conditioners.	8/2/2007
	Standby Generators	Capacity Need	82 MW	88 MW	8/10/2007
		Capacity Need	82 MW	90 MW	8/9/2007
		Capacity Need	82 MW	79 MW	8/8/2007
		Capacity Need	82 MW	85 MW	8/1/2006
		Monthly Test			
	Interruptible Service	Capacity Need	306 MW	301 MW	8/10/2007
		Capacity Need	306 MW	323 MW	8/9/2007
		Capacity Need	341 MW	391 MW	8/1/2006
		Communication Test	N/A	N/A	4/24/2007
8/05 – 7/06	Air Conditioners	Load Test	110 MW	107 MW	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/25/2006
8/04 – 7/05	Air Conditioners	Load Test	140 MW	148 MW	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Standby Generators	Monthly Test			
8/03 – 7/04	Air Conditioners	Load Test	110 MW	170 MW	7/14/2004
		Cycling Test	N/A	N/A	8/20/2003
	Water Heaters	Cycling Test	N/A	N/A	8/20/2003
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/28/2004

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/02 – 7/03	Air Conditioners	Load Test	120 MW	195 MW	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	82 MW	122 MW	8/21/2002
	Water Heaters	Load Test	5 MW	Included in Air Conditioners.	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	6 MW	Included in Air Conditioners.	8/21/2002
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/7/2003
		Communication Test	N/A	N/A	11/19/2002
8/01 – 7/02	Air Conditioners	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	150 MW	151 MW	8/17/2001
	Water Heaters	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	6 MW	Included in Air Conditioners.	8/17/2001
	Standby Generators	Capacity Need	80 MW	20 MW Estimation due to communication problems.	6/13/2002
		Monthly Test			
	Interruptible Service	Capacity Need	403 MW	370 MW	6/13/2002
		Communication Test	N/A	N/A	4/17/2002
8/00 – 7/01	Air Conditioners	Communication Test	N/A	N/A	9/14/2000
	Water Heaters	Communication Test	N/A	N/A	9/14/2000
	Standby Generators	Capacity Need	70 MW	70 MW	8/7/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/8/2001
7/99 – 8/00	Air Conditioners	Load Test	170-200 MW	175-200 MW	6/15/2000
	Water Heaters	Load Test	6 MW	Included in Air Conditioners.	6/15/2000
	Standby Generators	Capacity Need	70 MW	70 MW	7/2/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/17/2000
		Communication Test	N/A	N/A	10/20/1999

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/98 – 7/99	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/11/1999
		Communication Test	N/A	N/A	10/27/1998
9/97 – 9/98	Air Conditioners	Load Test	180 MW	170 MW	8/18/1998
	Water Heaters	Load Test	7 MW	7 MW	8/18/1998
		Communication Test	N/A	N/A	5/29/1998
	Standby Generators	Capacity Need	68 MW	58 MW	8/31/1998
		Capacity Need	68 MW	58 MW	6/12/1998
		Monthly Test			
	Interruptible Service	Capacity Need	570 MW	500 MW	8/31/1998
		Communication Test	N/A	N/A	5/29/1998
9/96 – 9/97	Air Conditioners	Communication Test	N/A	N/A	6/17/1997
	Standby Generators	Capacity Need	62 MW	50 MW	7/28/1997
		Capacity Need	62 MW	50 MW	7/15/1997
		Capacity Need	62 MW	50 MW	7/14/1997
		Capacity Need	62 MW	50 MW	12/20/1996
		Monthly Test			
	Interruptible Service	Capacity Need	650 MW	550 MW	7/28/1997
		Communication Tests	N/A	N/A	6/17/1997
		Communication Tests	N/A	N/A	10/16/1996

*Starting in 2010, a new category of event called an Economic Event has been added to the table.
**Corrected numbers from previous table filed.

APPENDIX E: PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

A list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known:

Line 12 of the LCR Table for Duke Energy Carolinas identifies cumulative future resource additions needed to meet customer load reliably. Resource additions may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting of new generation

APPENDIX F: TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES PLANNED OR UNDER CONSTRUCTION

There are no significant planned construction projects on the Duke Energy Carolinas' transmission system.

In addition, NCUC Rule R8-62(p) requires the following information.

1. For existing lines, the information required on FERC Form 1, pages 422, 423, 424 and 425: (Please see Appendix J for Duke Energy Carolinas' current FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 423.3, 424, 425, and 450.1.)

2. For lines under construction:
   - Commission docket number
   - Location of end point(s)
   - Length
   - Range of right-of-way width
   - Range of tower heights
   - Number of circuits
   - Operating voltage
   - Design capacity
   - Date construction started
   - Projected in-service date

3. For all other proposed lines, as the information becomes available:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.67		1
2	Jocassee Tie	Bad Creek Hydro	525.00	525.00	Tower	9.25		1
3	Jocassee Tie	McGuire Switching	525.00	525.00	Tower	119.85		1
4	McGuire Switching	Antioch Tie	525.00	525.00	Tower	54.40		1
5	McGuire Switching	Woodleaf Switching	525.00	525.00	Tower	29.95		1
6	Newport Tie	Progress Energy Rockingham	525.00	525.00	Tower	48.65		1
7	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.24		1
8	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	108.12		1
9	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.50		1
10	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.90		1
11	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	49.65		1
12	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	53.07		1
13								
14	TOTAL 525 KV LINES					576.27		12
15								
16	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.85		2
17	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.49		2
18	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.22		2
19	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.63		2
20	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.79		2
21	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.29		2
22	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.60		2
23	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.48		2
24	Belews Creek Steam	Ernest Switching Station	230.00	230.00	Tower	13.71		2
25	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.65		2
26	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.72		2
27	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.32		2
28	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.83		2
29	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.63		2
30	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.35		2
31	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.25		2
32	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.85		2
33	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.44		2
34	Central Tie	Anderson Tie	230.00	230.00	Tower	22.12		2
35	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.01		2
36					TOTAL	8,259.55		182

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.16		2
2	Cowans Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.67		2
3	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.25		2
4	Eno Tap Bent	Progress Energy (Roxboro)	230.00	230.00	Tower	13.74		2
5	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.76		2
6	Ernest Switching Station	Sadler Tie	230.00	230.00	Tower	12.61		2
7	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.52		2
8	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.16		2
9	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.52		2
10	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	28.62		2
11	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
12	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.95		2
13	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.93		2
14	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.61		2
15	Marshall Steam	Longview Tie	230.00	230.00	Tower	29.04		2
16	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.76		2
17	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.44		2
18	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.35		2
19	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.27		2
20	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	16.90		2
21	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	28.85		2
22	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.55		1
23	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.22		2
24	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.96		2
25	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.59		1
26	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.36		1
27	Oakboro Tie	Progress Energy Rockingham	230.00	230.00	Tower	5.13		2
28	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.62		2
29	Oconee Nuclear	Jocassee Switching	230.00	230.00	Tower & Pole	12.26		2
30	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.25		2
31	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.96		2
32	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.69		2
33	Pisgah Tie	Progress Energy Skyland Stm	230.00	230.00	Tower	14.41		2
34	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.65		2
35	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.70		2
36					TOTAL	8,259.59		162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.95		2
2	Riverbend Steam	Lincoln CT	230.00	230.00	Tower & Pole	11.59		2
3	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	5.61		2
4	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.12		2
5	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.33		2
6	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.63		1
7	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.80		2
8	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	21.85		2
9	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.46		2
10	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	35.92		2
11	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.36		2
12	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.05		2
13								
14	TOTAL 230 KV LINES					1,395.31		130
15								
16	Nantahala Hydro	Webster Tie	161.00	161.00	Tower	12.66		1
17	Nantahala Tie	Marble Tie	161.00	161.00	Tower	18.85		2
18	Nantahala Hydro	Santeetlah Pit Robbinsville	161.00	161.00	Tower	18.88		2
19	Tuckaseegee Tie	West Mill Tie	161.00	161.00	Tower & Pole	10.42		2
20	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.25		1
21	Webster Tie	Lake Emory S. S.	161.00	161.00	Tower	11.93		1
22	West Mill Tie	Lake Emory S. S.	161.00	161.00	Tower	6.76		1
23	West Mill Tie	Nantahala Tie	161.00	161.00	Tower	13.06		1
24	West Mill Tie	East Bryson	161.00	161.00	Tower & Pole	13.30		3
25								
26	TOTAL 161 KV LINES					107.16		14
27								
28	Dan River Steam	Appalachian Power	138.00	138.00	Tower & Pole	6.54		1
29	115 KV Lines		115.00	115.00	Tower & Pole	54.88		1
30	100 KV Lines		100.00	100.00	Tower	2,884.35		
31	100 KV Lines		100.00	100.00	Pole	640.25		
32	100 KV Lines		100.00	100.00	Underground	2.06		
33								
34	TOTAL 100 - 138 KV LINES					3,588.10		2
35								
36					TOTAL	8,259.59		162

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	66 KV Lines		66.00	66.00	Pole	104.83		1
2								
3	TOTAL 66 KV LINES					104.83		1
4								
5	44 KV Lines		44.00	44.00	Tower	183.25		
6	44 KV Lines		44.00	44.00	Pole	2,178.66		
7	44 KV Lines		44.00	44.00	Underground	0.34		1
8								
9	TOTAL 44 KV LINES					2,362.25		1
10								
11	33 KV Lines		33.00	33.00	Pole	14.65		
12	24 KV Lines		24.00	24.00	Pole	84.64		
13	24 KV Lines		24.00	24.00	Underground	0.44		1
14	12 KV Lines		12.00	12.00	Tower & Pole	25.67		
15	12 KV Lines		12.00	12.00	Underground	0.22		1
16								
17	TOTAL 12-33 KV LINES					125.62		2
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,259.59		162

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
	20,355,902	99,736,823	120,092,725					13
	20,355,902	99,736,823	120,092,725					14
								15
1272								16
1272								17
954 & 1272								18
2156								19
954								20
954								21
2156								22
954								23
1272								24
2156								25
2156								26
2156								27
2156								28
954								29
1272								30
954								31
1272								32
1272								33
954								34
954								35
	161,478,509	1,228,987,846	1,390,466,355	716,074	15,727,295		16,442,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the *pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)*

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
795								2
1272								3
1272								4
1272								5
1272								6
954								7
954								8
2156								9
1272								10
954								11
795								12
954								13
954								14
1272								15
1272								16
954								17
1272								18
1272								19
954								20
954								21
954								22
954								23
954								24
954								25
954								26
954								27
1272								28
2156								29
1272								30
954								31
795								32
954								33
954								34
795								35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
795								2
1272								3
795								4
795								5
954								6
2515								7
954								8
1272								9
954								10
954								11
954								12
	41,317,981	220,519,462	261,837,443					13
	41,317,981	220,519,462	261,837,443					14
								15
795								16
795								17
636								18
795								19
397.5								20
636								21
795								22
795								23
954								24
	3,422,657	73,995,073	77,417,730					25
	3,422,657	73,995,073	77,417,730					26
								27
477								28
								29
								30
								31
								32
	68,746,288	567,900,634	636,646,922					33
	68,746,288	567,900,634	636,646,922					34
								35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
	4,464,582	21,632,669	26,097,251					2
	4,464,582	21,632,669	26,097,251					3
								4
								5
								6
								7
	22,606,882	240,793,751	263,400,633					8
	22,606,882	240,793,751	263,400,633					9
								10
								11
								12
								13
								14
								15
	564,217	4,409,434	4,973,651					16
	564,217	4,409,434	4,973,651					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				715,074	15,727,295		16,442,369	35
	161,478,509	1,228,937,846	1,390,456,355	715,074	15,727,295		16,442,369	36

Name of Respondent Duke Energy Carolinas, LLC	This Report is: (1) _ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h

For column (h) the number of circuits - 1 & 2

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) are ACSR shown in MCM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Overhead: New Lines						
2	Beatles Ford Ret Tap		1.70	Pole	6.00	1	
3	Parkwood Ret Tap		0.11	Pole	9.00	1	
4	Cleveland County School Tap		0.84	Towers	20.00	2	
5	Cathey Rd Tap		0.90	Pole	11.00	1	
6	Institute for B & H Safety Tap		0.19			1	
7	Piercetown to Plainview Tap		5.30		9.00	2	
8	Indian land & Charlotte #2 Tap		0.04	Pole	75.00	1	
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	Overhead: Major Rebuild						
24	Ebert Rd Tap	Buck Tie - Winston Tie	2.53		9.00	2	
25	Buzzard Roost Hydro	International Paper Tap	5.46		8.00	2	
26	Central Tie	Greenlawn Switching Station	0.28		96.00	2	
27	Kent Line	Hillside Line to Shoal Line	0.02	Pole	65.00	1	
28	Armory Bent	N Greenwood Retail	0.75		17.00	2	
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		18.12		327.00	18	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
556.5	ACSR		100	461,933	1,114,037	682,798		2,258,768	2
1272.0	ACSR		100		24,013	46,764		70,777	3
556.0	ACSR		44	15,393	356,495	218,497		590,385	4
336.0	ACSR		100	748,190	286,710	175,725		1,210,625	5
556.0	ACSR		100		83,646	51,268		134,914	6
954.0	ACSR		100		3,070,808	1,882,108		4,952,916	7
336.0	ACSR		44		33,050	20,256		53,306	8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
954.0	ACSR		100		1,114,259	682,933		1,797,192	24
556.0	ACSR		100		1,535,851	941,328		2,477,179	25
477.0	ACSR		100		3,473,526	2,128,936		5,602,462	26
556.0	ACSR		44		247,741	151,840		399,581	27
556.0	ACSR		100		549,952	337,068		887,020	28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,225,516	11,890,063	7,319,621		20,435,125	44

Name of Respondent Duke Energy Carolinas, LLC	This Report is: (1) _ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 1 Column: l

For all of column "l", "m" and "n" all or portion of the cost is in account 106

Schedule Page: 424 Line No.: 6 Column: d

No structures used in the new line

Schedule Page: 424 Line No.: 7 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 24 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 25 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 26 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 28 Column: d

Towers & Poles used in the new line

GENERATION AND ASSOCIATED TRANSMISSION FACILITIES SUBJECT TO CONSTRUCTION DELAYS

A list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the NCUC Staff, the reporting utility shall supply a statement of the economic impact of such delays:

There are no delays over six months in the stated in-service dates.

2011 FERC Form 715

The 2011 FERC Form 715 filed April 2011, is confidential and filed under seal.

APPENDIX G: OTHER INFORMATION (ECONOMIC DEVELOPMENT)

Customers Served Under Economic Development:

In the NCUC Order issued in Docket No. E-100, Sub 97, dated November 15, 2002, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. There are no significant changes to the incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) since the 2010 Carolinas IRP.

APPENDIX H: NON-UTILITY GENERATION/CUSTOMER-OWNED GENERATION/STAND-BY GENERATION:

In NCUC Order in Docket No. E-100, Sub 111, dated July 11, 2007, the NCUC required North Carolina utilities to provide a separate list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and standby generating facilities, to the extent possible. Duke Energy Carolinas' response to that Order was based on the best available information, and the Company has not attempted to independently validate it. In addition, some of that information duplicates data that Duke Energy Carolinas supplies elsewhere in this IRP.

The Company has continued to add small non-utility electric generation in 2011. A separate list is not included in the 2011 IRP, however the total additions are reflected in Tables 5.E and 5.F, and the Company has included a full list in its annual status report filed in Docket No. E-100, Sub 41B.

APPENDIX I: WHOLESALE PROJECTIONS FROM EXISTING AND POTENTIAL CUSTOMERS

Table I.1 below provides the historical and projected growth in peak loads for the Company's wholesale customers. The values are summer peaks at generation. The wholesale customer growth rates vary and none are the same as the historical growth rate in Duke Energy Carolinas' retail load. With respect to wholesale sales contracts, the Company has developed econometric forecasting models for the larger wholesale customer in a process similar to that used for retail to produce MWH sales forecasts. For smaller wholesale customers, however, their forecasted growth is assumed to be the same as Duke Energy Carolinas' retail growth.

It is important to note that the growth rates for Central and NCEMC Supplemental Requirements) are primarily driven by terms of the contract. The Central Sale provides for a seven year "step-in" to Central's full load requirement such that the Company will provide 15% of Central's total member cooperative load in Duke's Balancing Authority Area requirement in 2013. This initial load requirement will be followed by subsequent 15% annual increases in load over the following six years up to a total of 100% of Central's load requirements. The NCEMC Supplemental Requirements sale is essentially a fixed quantity of capacity and energy specified by the contract

The wholesale sales contracts, shown in Table 3.D, are net of resources provided by the customer.

TABLE I.1 (CONFIDENTIAL)

[redacted]

APPENDIX J: CARBON NEUTRALITY PLAN

Greenhouse Gas Reduction Compliance Plan – Cliffside Unit 6

On January 29, 2008, the NCDAQ issued the Air Quality Permit to Duke Energy Carolinas for the Cliffside Unit 6. The Permit specifically requires that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan), and specifically obligates Duke Energy Carolinas to take the following actions in recognition of NCDAQ's issuance of the Permit for Cliffside Unit 6: (1) retire 800 MWs of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, which is in addition to the retirement of Cliffside Units 1 – 4; (2) accommodate, to the extent practicable, the installation and operations of future carbon control technology; and (3) take additional actions to make Cliffside Unit 6 carbon neutral by 2018.

With regard to obligation (1) identified above, as shown in Table J.1 below, Duke Energy Carolinas proposes to retire up to the following generating units to satisfy the required retirement schedule set forth in the Greenhouse Plan.

<u>Table J.1</u> - Cumulative Coal Plant Retirements

	Greenhouse Plan Retirement Schedule Capacity in MW	IRP Retirement Schedule Capacity in MW (per Table 5.D)[1]	Description for IRP Retirement Schedule
by end of 2011		113	Buck 3 & 4
by end of 2012		389	Dan River 1-3
by end of 2015	350	1159	Riverbend 4 - 7, Buck 5 & 6
by end of 2016	550	1159	Note [2]
by end of 2018	**800**	**1159**	

[1] In the 2011 IRP, this data appears in Table 5.D, page 50. Plant retirements that were applicable to the first obligation were put in this table. References will be updated with the 2011 IRP.
[2] The IRP Retirement Schedule indicates that the retirements would exceed the Greenhouse Plan by close to 50%.

With respect to obligation (2) listed above, the requirement to build Cliffside Unit 6 to accommodate future carbon technologies has been met by allocating space at the 1100 acre site for this equipment and incorporating practical energy efficiency designs into the plant.

With respect to obligation (3) to render Cliffside Unit 6 carbon neutral by 2018, the proposed plan to achieve this requirement is set forth below. The Greenhouse Gas

Reduction Plan states that the plan for carbon neutrality:

may include energy efficiency, carbon free tariffs, purchase of credits, domestic and international offsets, additional retirements or reduction in fossil fuel usage as carbon free generation becomes available, and carbon reduction through the development of smart grid, plug in hybrid electric vehicles or other carbon mitigation projects. Such actions will be included in plans to be filed with the NCUC and will be subject to NCUC approval, including appropriate cost recovery of such actions. In addition, the plans shall be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to the NCUC.

Duke Energy Carolinas is including the plan for carbon neutrality in this 2011 IRP in order to satisfy the requirement to file and seek approval of the plan from the NCUC as required by the NCDAQ Air Permit.

The estimated emissions reductions required to render Cliffside Unit 6 carbon neutral in 2018 is approximately 5.3 million tons of carbon dioxide (the Emission Reduction Requirement). The Company calculated the estimated emission reductions by estimating the actual tons of carbon dioxide emissions that will be released per year from Cliffside Unit 6 less 681,954 tons of carbon dioxide emissions that was historically generated from Cliffside Units 1 – 4 and will be eliminated by the retirement of these units. (See Table J.2 below.)

Table J.2 - Emission Reduction Requirement

Actions	**Tons of CO_2 Equivalent Emissions**	**Notes**
Cliffside Unit 6	6,000,000	Expected Annual Emissions (based on an approximate 90% capacity factor)
Less Cliffside Units 1 – 4	(681,954)	Average of emissions in 2007 & 2008[1]
Total Increase	**5,318,055**	**Emissions Reduction Requirement**

[1]The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modification under the Clean Air Act Prevention of Significant Deterioration regulations.

The Company's plan for meeting the Emissions Reductions Requirements includes actions from multiple categories and associated methodologies for determining the offset value known as "Qualifying Actions" (defined below and as further indicated in Table J.3). The Company requests approval from the NCUC of the method of calculating the Emission Reduction Requirements and emissions offset values of the Qualifying Actions during the 2011 IRP review process.

For 2018, the Company has identified approximately 9.9 million annual tons of carbon dioxide emissions reductions and a life-time credit of 600,000 tons of carbon dioxide bio-sequestration as eligible Qualifying Actions. (See Table J.3) The Qualifying Actions include the avoidance of carbon dioxide emission releases from coal plant retirements, addition of renewable resources, implementation of energy efficiency measures, nuclear and hydropower capacity upgrades. This also includes the expected retirement of coal-fired operations at Lee Units 1, 2 and 3 in South Carolina in 2015. In addition, carbon dioxide bio-sequestration offsets from the Greentrees program, which sequesters carbon as trees grow, is identified as a Qualifying Action.

While the reductions associated for retirements for each of the coal plants shall be the same each year, the reductions for the remaining Qualifying Actions will vary based on actual results for each of the categories and the then current system carbon intensity factor. The system carbon intensity factor shall be equal to the actual carbon dioxide emissions of all Company-owned generation dedicated for Duke Energy Carolina customers divided by the megawatt hours generated by those same resources (the "Conversion Factor").

Table J.3 - Qualifying Actions for carbon dioxide emission reductions

Categories	Tons of CO_2 Equivalent Emissions	Methodology Description
Buck 3	216,202	Average of emissions in 2007 & 2008[1]
Buck 4	139,429	Average of emissions in 2007 & 2008[1]
Buck 5	606,837	Average of emissions in 2007 & 2008[1]
Buck 6	653,860	Average of emissions in 2007 & 2008[1]
Riverbend 4	462,314	Average of emissions in 2007 & 2008[1]
Riverbend 5	435,895	Average of emissions in 2007 & 2008[1]
Riverbend 6	684,010	Average of emissions in 2007 & 2008[1]
Riverbend 7	710,023	Average of emissions in 2007 & 2008[1]
Dan River 1	249,900	Average of emissions in 2007 & 2008[1]
Dan River 2	282,944	Average of emissions in 2007 & 2008[1]
Dan River 3	677,334	Average of emissions in 2007 & 2008[1]
Lee 1 [5]	335,583	Average of emissions in 2007 & 2008[1]
Lee 2 [5]	390,965	Average of emissions in 2007 & 2008[1]
Lee 3 [5]	783,658	Average of emissions in 2007 & 2008[1]
Conservation	1,189,268	In 2018, 2,973,170 MWH "Conservation and Demand Side Management Programs"[2] is multiplied by a Conversion Factor of 0.40.
Renewable Energy	1,068,370	In 2018, 610 MW per the Table 8.E "MW Nameplate Capacity".[3] Is multiplied by an assumed 30% (wind), 20% (solar), and 85% (biomass) capacity factor and a Conversion Factor of 0.40.
Bridgewater Hydro	7,997	See Note 5 in the "Assumptions of Load, Capacity, and Reserve Table" indicates 8.75 MW increase in capacity. This is multiplied by a 26% capacity factor and a Conversion Factor of 0.40.
Nuclear Uprates	560,920	Assumed 174 MW of nuclear uprates by June of 2018.[4] Assumed a 92% capacity factor and a Conversion Factor of 0.40.
Total Annual	9,455,509	

[1] The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modifications under the Clean Air Act Prevention of Significant Deterioration regulations. Company reserves the right to use any credits for reduction of nitrogen oxide, sulfur dioxide and carbon dioxide emissions generated by retirement of units retired under the plan consistent with provisions of State and federal law.
[2] Data is from Table 4.A, page 34 of the 2011 IRP.
[3] Data is from the Table 8.E on page 93 of the 2011 IRP. Actual nameplate capacity is 610 MW. The contribution to peak is 304 MW.
[4] Data is a portion of the total capacity addition on page 87 of 2011 IRP prior to June 2018.
[5] Lee Units 1, 2 and 3 are planned for retirement by January 1, 2015. Alternatively, Duke Energy is considering converting one or more of these units to natural gas to allow continued operation for peak

generation demand only (at a low annual capacity factor). Any CO_2 from operating with natural gas would be subtracted from the reductions shown in the table.

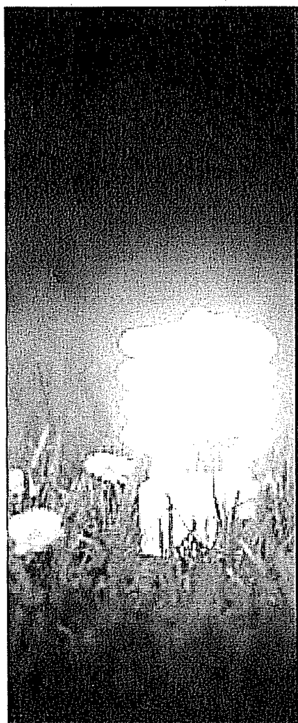
If the method described above is approved, Duke Energy Carolinas shall provide a compliance report (Compliance Reports) in the 2019 IRP filing indicating what Qualifying Actions were used to meet the Emission Reduction Requirement in 2018. The expected Qualifying Actions total of 9.9 million tons of emission reductions by 2018. The Company's proposed Qualifying Actions clearly demonstrate that identified reductions can more than exceed the Required Emissions Reduction estimate of 5.3 million tons. The Company therefore requests the ability to alter the mix of actions undertaken, and even to eliminate some completely, in its discretion so long as the annual emissions reductions achieved total at least 5.3 million tons in accordance with the NCDAQ Air Permit.

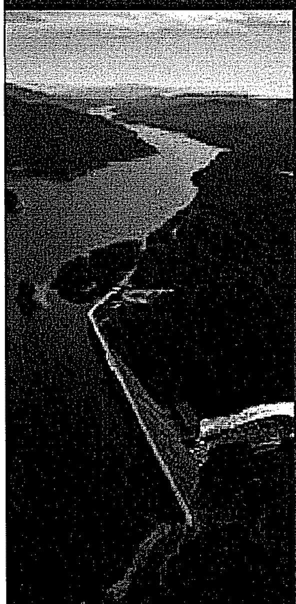
APPENDIX K: CROSS-REFERENCE OF IRP REQUIREMENTS

The following table cross-references IRP regulatory requirements for North Carolina and South Carolina, and identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
Forecast of Load, Supply-side Resources, and Demand-Side Resources. • 10 year history of customers & energy sales • 15 year forecast w & w/o energy efficiency • Description of supply-side resources	Ch 3 Ch 3 Ch 5 & App C	NC R8-60 h (i) 1(i) NC R8-60 h(i) 1(ii) NC R8-60 h(i) 1(iii)	Yes Yes Yes
Generating Facilities • Existing Generation • Planned Generation • Non Utility Generation • Proposed Generation Units at Locations not known • Generating Units Projected to be Retired • Generating Units with plan for life extension	Ch 5 A Ch 8 & App A Ch 5 D Ch 8 & App A Ch 5 A N/A	NC R8-60 h (i) 2(i)(a-f) NC R8-60 h (i) 2(ii)(a-d) NC R8-60 h (i) 2(iii)	Yes Yes Yes Yes Yes
Reserve Margin	Ch 8	NC R8-60 h (i) 3	Yes
Wholesale Contract for the Purchase and Sale of Power • Wholesale Purchase Power Contract • Request for Proposal • Wholesale power sales contracts • Wholesale projections (existing and undesignated)	Ch 5 D Ch 5 D Ch 3 & App I App I	NC R8-60 h (i) 4(i) NC R8-60 h (i) 4(ii) NC R8-60 h (i) 4(iii) NCUC 09 IRP req (6)	Yes Yes Yes Yes
Transmission Facilities , planned & under construction Transmissions System Adequacy FERC Form 1 (pages 422-425) FERC Form 715	App F Ch 7 App F App F	NC R8-60 h (i) 5	Yes Yes Yes Yes
Energy Efficiency and Demand Side Management • Existing Programs • Future Programs • Rejected Programs • Consumer Education Programs • DSM projected reliance	Ch 4 Ch 4 Ch 4 Ch 4 App D	NC R8-60 h (i) 6(i) NC R8-60 h (i) 6(ii) NC R8-60 h (i) 6(iii) NC R8-60 h (i) 6(iv) NCUC 09 IRP req (7)	Yes Yes Yes Yes Yes
Assessment of Alternative Supply-Side Energy Resource • Current and Future Alternative Supply-Side • Rejected Alternative Supply-Side Energy Resource	Ch5C & App C Ch5C & App C	NC R8-60 h (i) 7(i) NC R8-60 h (i) 7(ii)	Yes Yes
Evaluation of Resource Options (Quantitative Analysis)	App A	NC R8-60 h (i) 8	Yes
Cost benefit analysis of each option Levelized Bus-bar Costs	App C	NC R8-60 h (i) 9	Yes
Other Information (economic development)	App G		No
Legislative and Regulatory Issues	Ch 6		Yes
Supplier's Program for Meeting the Requirements Shown in its Forecast in an Economic and Reliable Manner, including EE and DSM and Supply-Side Options	Ch 1, Ch 8 & App A		Yes
Supplier's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable	Ch 8, App A		Yes
Greenhouse Gas Reduction Compliance Plan	App J		Yes

EXHIBIT ______





Integrated Resource Plan

TVA's Environmental & Energy Future

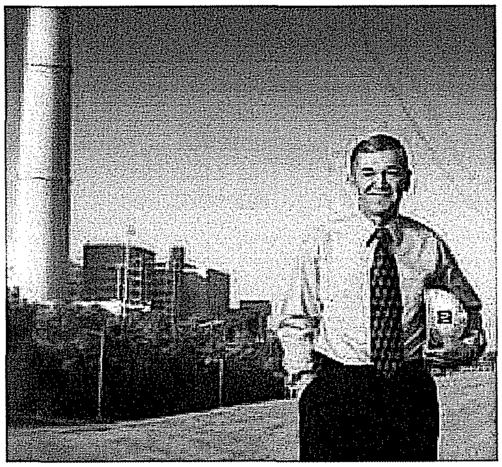
March 2011

TVA

SC EXHIBIT 24

Message from the CEO

TVA operates one of the largest power systems in the United States. With a generating capacity of more than 34,000 megawatts, we meet the daily electricity needs for an 80,000-square-mile region where more than 9 million people live, work and go to school. That's an enormous responsibility, and one we take very seriously.



A power system large and reliable enough to handle that responsibility doesn't come about by accident. It's the culmination of work by thousands of skilled professionals, and it all starts with focused and detailed planning.

Planning a power system is complex work that involves hundreds of variables, such as consumer trends, fuel and material costs, regulations, technology advancements and the weather. It's complicated even further by the need to forecast needs and conditions decades into the future.

TVA's new integrated resource plan is a critical part of our overall planning effort. It is a comprehensive study of options and strategies and their potential economic and environmental outcomes. The plan was shaped by input from the businesses, industries and regional leaders, as well as ordinary people, whose lives and livelihoods depend on the electricity supplied by TVA. The result of this two-year exercise gives us a sound basis for making better long-term decisions.

In addition, our integrated resource plan will help us fulfill TVA's renewed vision to become one of the nation's leading providers of low-cost and cleaner energy by 2020. The options that have been identified from this process involve reducing TVA's reliance on coal, increasing our supply of nuclear and renewable energy, and working in partnership with local utilities and the people they serve to use energy more efficiently.

Like most things, the cost of electricity is not likely to stay flat in the years ahead. Our challenge will be to keep power affordable while carrying out our vital work with the least impact on the environment today and for future generations.

Tom Kilgore

Tom Kilgore

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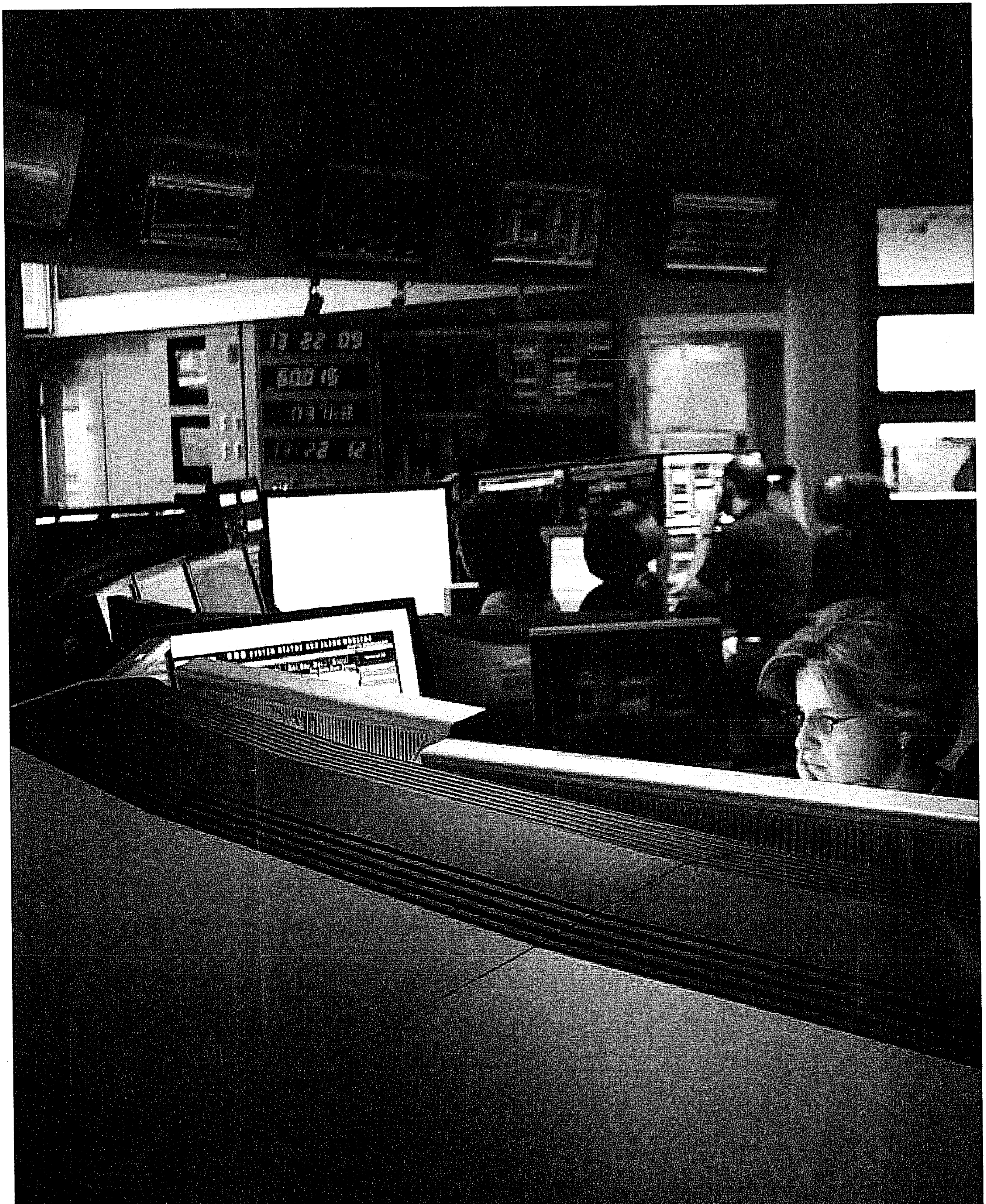
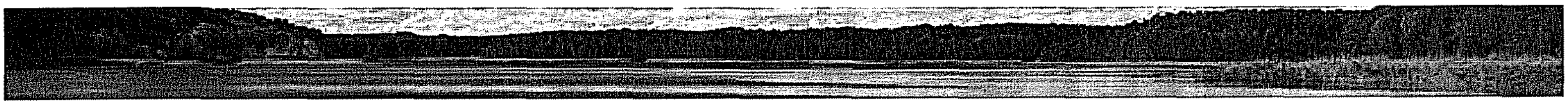
Appendix E





EXECUTIVE SUMMARY

Contents

Overview

The Tennessee Valley Authority's (TVA) Integrated Resource Plan (IRP), entitled TVA's Environmental and Energy Future, serves as a roadmap for identifying the resources that are acceptable and available to meet the energy needs of the Tennessee Valley region over the next 20 years. It addresses the demand for power in the region, the options available for meeting that demand and the potential environmental, economic and operating impacts of each.

This endeavor aligns with TVA's Environmental Policy and will serve as a guide for TVA to fulfill its renewed vision—to become one of the nation's leading providers of low-cost and cleaner energy by 2020. TVA is committed to lead the nation in improved air quality and increased nuclear production and to lead the Southeast in increased energy efficiency. This vision will be accomplished as TVA continues to carry out the mission established by Congress in 1933.

The current planning environment that confronts TVA is one of the most challenging in TVA's history. Therefore, TVA must ensure that its strategy is robust, regardless of future conditions, and enables TVA to navigate through these challenges in a way that best supports its multiple responsibilities. This IRP establishes a strategic direction for TVA and provides it with the flexibility to make the best decisions in a dynamic, ever-changing regulatory and economic environment.

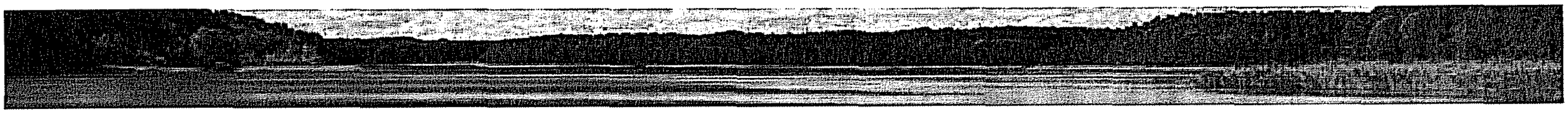


Figure 1 shows the Reference Case: Spring 2010 forecast of peak demand over the 20-year planning horizon. The figure also illustrates the range of load forecasts considered within this IRP, with the highest and lowest forecasts representing the upper and lower bounds.

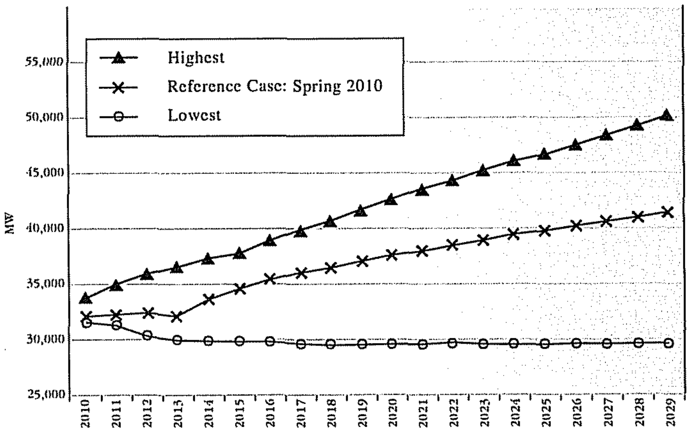


Figure 1 – Peak Load Forecast

Figure 2 shows the capacity gap for the Reference Case: Spring 2010 forecast over the 20-year planning horizon. The figure also illustrates the capacity gap based on the range of peak loads considered in this IRP. The capacity gaps were developed by adding a planning reserve margin to the peak load forecast and subtracting existing resources. Additional detail on the need for power analysis is included in Chapter 4 – Need for Power Analysis.

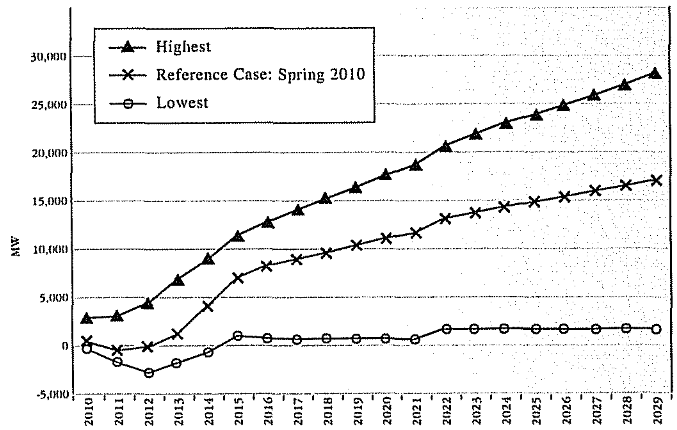
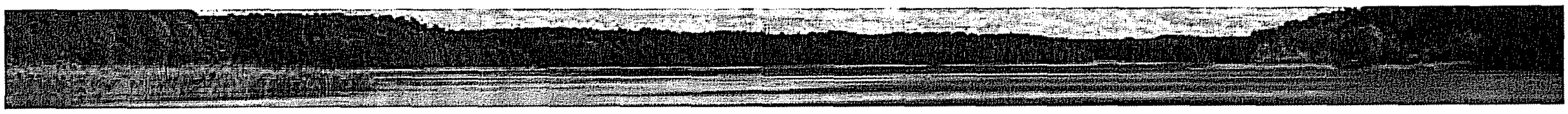


Figure 2 – Capacity Gap



Approach

Scenario Planning

A scenario planning approach was utilized for the development of this IRP. TVA carried out its analysis in a "no-regrets" framework. This framework defined a process in which all relevant and available information was analyzed in a careful and considered fashion, with significant attention paid to what would happen if the future unfolds in an unexpected way.

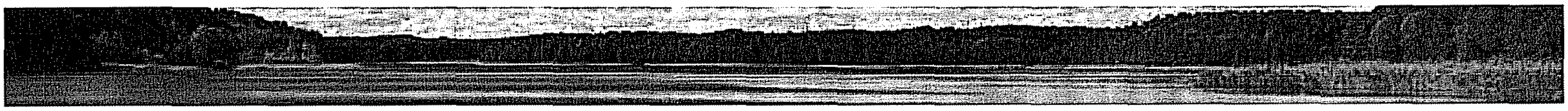
In other words, strategic options were analyzed not only from the perspective of what was expected to occur in the future, but also from the perspective of what was possible to occur in the future. Using this framework, decisions made today and in the near future are not overly dependent on the future unfolding exactly as expected. Therefore, this IRP should provide benefit and value to stakeholders even if the future turns out to be different than predicted.

Scenarios and planning strategies form the basic building blocks of the IRP analysis. Scenarios do not predict the future, but rather portray the range of possible "worlds" that TVA may encounter in the future based on a number of uncertainties outside of TVA's control. Scenarios were also used to test resource selection and reflect key stakeholder interests.

Factors that differed between scenarios included economic growth, inflation, fuel prices, demand growth and regulatory environments. Uncertainties varied among scenarios to highlight how decisions would change under different conditions.

Six unique scenarios were developed for this IRP along with two iterations of a reference forecast. Scenario 7 – Reference Case: Spring 2010 was used in the Draft IRP analysis and was refreshed with Scenario 8 – Reference Case: Great Recession Impacts Recovery between the Draft and final IRP. The following eight scenarios were used:

- Scenario 1 – Economy Recovers Dramatically
- Scenario 2 – Environmental Focus is National Priority
- Scenario 3 – Prolonged Economic Malaise
- Scenario 4 – Game-Changing Technology
- Scenario 5 – Energy Independence
- Scenario 6 – Carbon Regulation Creates Economic Downturn



- Scenario 7 – Reference Case: Spring 2010
- Scenario 8 – Reference Case: Great Recession Impacts Recovery

Additional details on the scenarios are included in Chapter 6 – Resource Plan Development and Analysis.

Recommended Planning Direction Development

The Draft IRP evaluated five specific planning strategies. These planning strategies described a broad range of business options that TVA could adopt and were built upon key decisions within TVA's control. Components such as renewable generation additions, nuclear expansion and market purchases varied among planning strategies. The following planning strategies were considered in the Draft IRP:

- Strategy A – Limited Change in Current Resource Portfolio
- Strategy B – Baseline Plan Resource Portfolio
- Strategy C – Diversity Focused Resource Portfolio
- Strategy D – Nuclear Focused Resource Portfolio
- Strategy E – EEDR and Renewables Focused Resource Portfolio

Each planning strategy was evaluated across the first seven scenarios. The results were summarized using a scorecard designed to identify financial, risk and strategic factors to consider when selecting a Recommended Planning Direction.

Based on the preliminary results, TVA focused on the top three ranked planning strategies (Strategies B, C and E) for further evaluation. Additional detail on the Draft IRP results is included in Chapter 7 – Draft Study Results.

A high-level summary of the process used for developing the final IRP is shown in Figure 3.

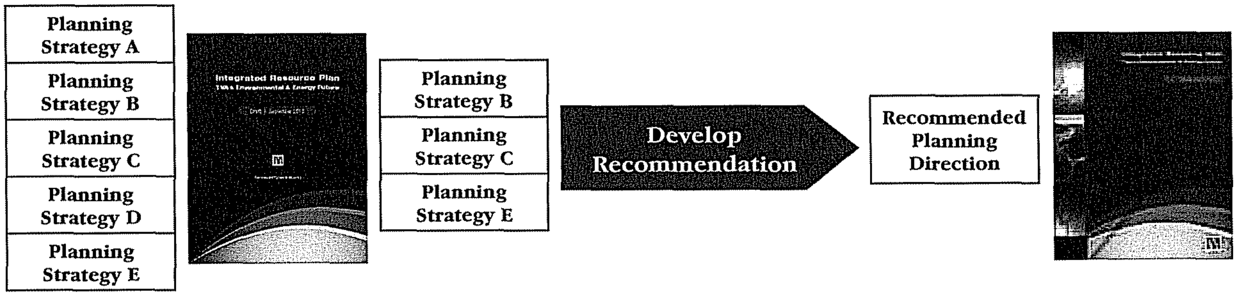


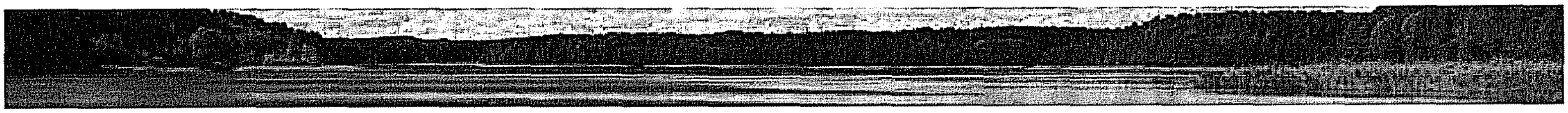
Figure 3 – Final IRP Development

A key objective in transitioning from the Draft to the final IRP was to identify a Recommended Planning Direction. The preliminary results and findings of the Draft IRP were used to establish boundaries for evaluating new combinations of planning strategy components through an optimization framework. In addition, input received during the public comment period was reviewed in detail and appropriately incorporated into the analysis. This approach produced more comprehensive results by allowing unique combinations of resources to be tested in addition to those directly considered in the Draft IRP. A summary of the options considered for the final IRP is shown in Figure 4.

<table>
<tr><th>Components</th><th colspan="5">Range of Options Tested</th></tr>
<tr><td>EEDR</td><td>2,100 MW & 5,900 annual GWh reductions by 2020</td><td colspan="2">3,600 MW & 11,400 annual GWh reductions by 2020</td><td colspan="2">5,100 MW & 14,400 annual GWh reductions by 2020</td></tr>
<tr><td>Renewable additions</td><td>1,500 MW competitive resources or PPAs by 2020</td><td>2,500 MW competitive resources or PPAs by 2020</td><td>2,500 MW competitive resources or PPAs by 2029</td><td>3,500 MW competitive resources or PPAs by 2020</td><td>3,500 MW competitive resources or PPAs by 2029</td></tr>
<tr><td>Coal-fired capacity idled</td><td>2,400 MW total fleet reductions by 2017</td><td>3,200 MW total fleet reductions by 2017</td><td colspan="2">4,000 MW total fleet reductions by 2017</td><td>4,700 MW total fleet reductions by 2017</td></tr>
</table>

Figure 4 – Optimization Framework for the final IRP Analysis

The Recommended Planning Direction was evaluated in all eight scenarios. The results were used to build a fully populated scorecard with ranking and strategic metrics. The completed scorecard was compared with the Draft IRP results to evaluate improvements between previously considered planning strategies. Additional detail on the Recommended Planning Direction results is included in Chapter 8 – Final Study Results and Recommended Planning Direction.



Strategic Findings

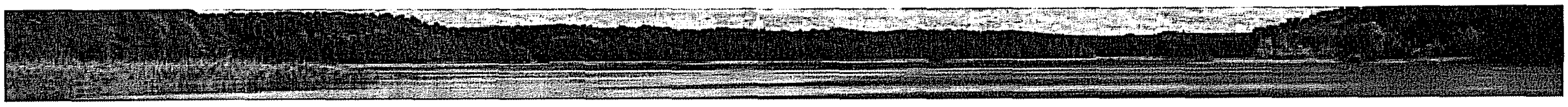
The following strategic findings emerged from the IRP analysis:

- Expanded EEDR portfolios perform well; the mid level portfolio provided the best balance of cost and implementation risk
- Renewable generation above existing wind contracts played a role in future resource portfolios, assuming certain costs
- Some increased idling of coal-fired capacity was favorable compared to adding environmental controls to the existing fleet
- Coal-fired capacity was only added in scenarios with high load growth
- Pumped-storage added needed operational flexibility
- Nuclear expansion was selected in most cases, except scenarios with no load growth
- Natural gas-fired capacity was selected in most cases after 2020, except when needed earlier to meet high load growth or to provide grid reliability

Recommended Planning Direction

This IRP provides TVA with a strategic direction and the flexibility to make sound choices in a dynamic, ever-changing regulatory and economic environment. The Recommended Planning Direction is the most balanced in terms of cost, financial risk and other strategic considerations and provides direction by articulating a 20-year roadmap.

Components of the Recommended Planning Direction are based upon extensive modeling, in-depth stakeholder input and the assessment of quantified and non-quantified risks. They also allow for flexibility to adapt to future conditions by providing guideline ranges and timeframes for each component of the planning strategy. A summary of the Recommended Planning Direction is shown in Figure 5.



Public Participation

Public participation was a significant component of the IRP process. In an effort to develop the plan in a transparent manner, TVA offered multiple opportunities for the public to contribute to and influence the development of this IRP. These opportunities included two series of public meetings, written comments, webinars, briefings, a web-based questionnaire, and a phone survey. The goal for all public participation opportunities was to encourage others to share their views on issues they believe TVA should focus on as it plans for the region's future energy needs.

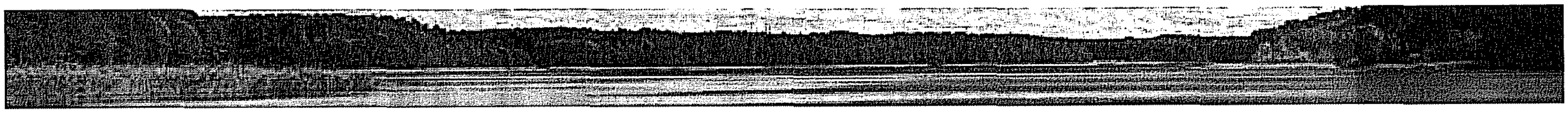
In addition to public participation, TVA also formed a Stakeholder Review Group (SRG). This group consisted of 16 individuals representing a wide range of interests. Members of the group were asked to provide TVA with their viewpoints on the IRP process, assumptions, analyses and results. TVA met approximately every month with the SRG throughout the IRP process to discuss strategic findings.

Need for Power Analysis

As a part of the IRP analysis, TVA developed a forecast of the need for power, referred to in the electric utility industry as "demand." To develop this forecast, the following four basic steps were taken:

1. Demand for electricity (peak demand and energy sales) was forecasted for a 20-year planning horizon (Figure 1)
2. Firm requirements were calculated to determine generation capacity required by adding forecasted demand to a planning contingency. The planning contingency allowed for unforeseen events, inaccuracies or unplanned unit outages and other resource limitations
3. Existing generation resources available to meet the forecasted demand were identified
4. The need for power was calculated by comparing the firm requirements to the existing viable generation resources. The difference between the two defines the need for additional resources over the planning period. This is referred to as "the capacity gap" (Figure 2)

TVA expects the need for power to continue to grow due to economic recovery, population growth and other factors. However, this growth is expected to occur at a lower rate than historical average.



Component	Guideline MW Range	Window of Time	Recommendations
EEDR	3,600-5,100 (11,400-14,400 GWh)	By 2020[1]	Expand contribution of EEDR in the portfolio
Renewable additions	1,500-2,500[2]	By 2020[1]	Pursue cost effective renewable energy
Coal-fired capacity idled	2,400-4,700[3]	By 2017	Consider increasing amount of coal-fired capacity idled
Energy storage	850[4]	2020-2024	Add pumped-storage capacity
Nuclear additions	1,150-5,900[5]	2013-2029	Increase contribution of nuclear generation
Coal additions	0-900[6]	2025-2029	Preserve option of generation with carbon capture
Natural gas additions	900-9,300[7]	2012-2029	Utilize natural gas as an intermediate supply source

1 – This range includes EEDR savings achieved through 2010. The 2020 range for EEDR and renewable energy does not preclude further investment in these resources during the following decade

2 – TVA's existing wind contracts that total more than 1,600 MW are included in this range. Values are nameplate capacity. Net dependable capacity would be lower

3 – TVA has previously announced plans to idle 1,000 MW of coal-fired capacity, which is included in this range. MW values based on maximum net dependable capacity

4 – This is the expected size of a new pumped-storage hydro facility

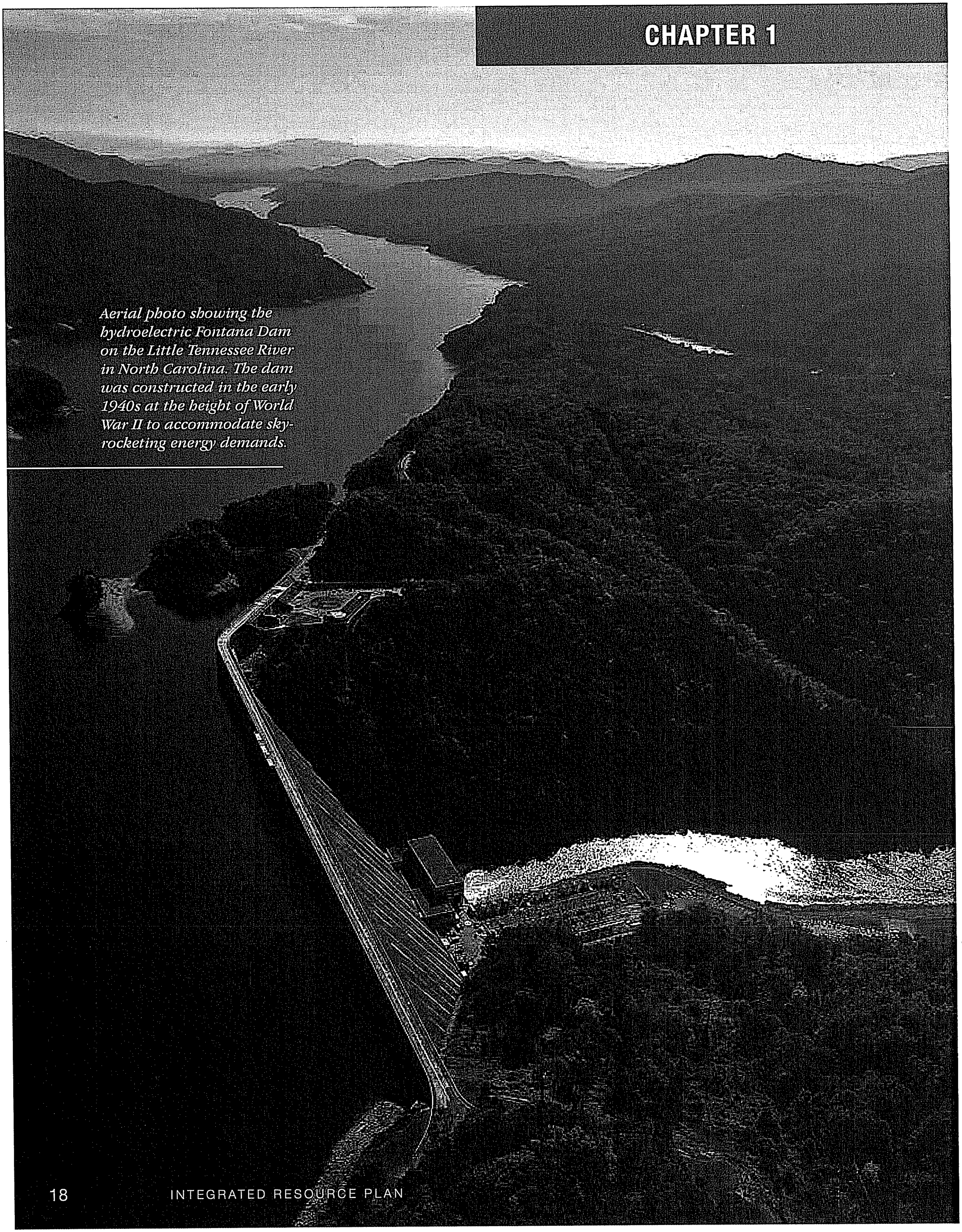
5 – The completion of Watts Bar Unit 2 represents the lower end of this range

6 – Up to 900 MW of new coal-fired capacity is recommended between 2025 and 2029

7 – The completion of John Sevier combined cycle plant represents the lower end of this range

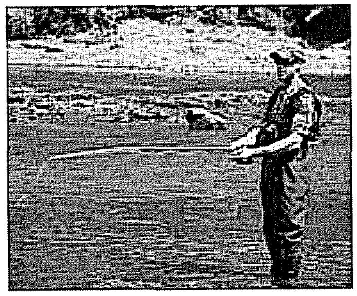
Figure 5 – The Recommended Planning Direction

CHAPTER 1



Aerial photo showing the hydroelectric Fontana Dam on the Little Tennessee River in North Carolina. The dam was constructed in the early 1940s at the height of World War II to accommodate sky-rocketing energy demands.

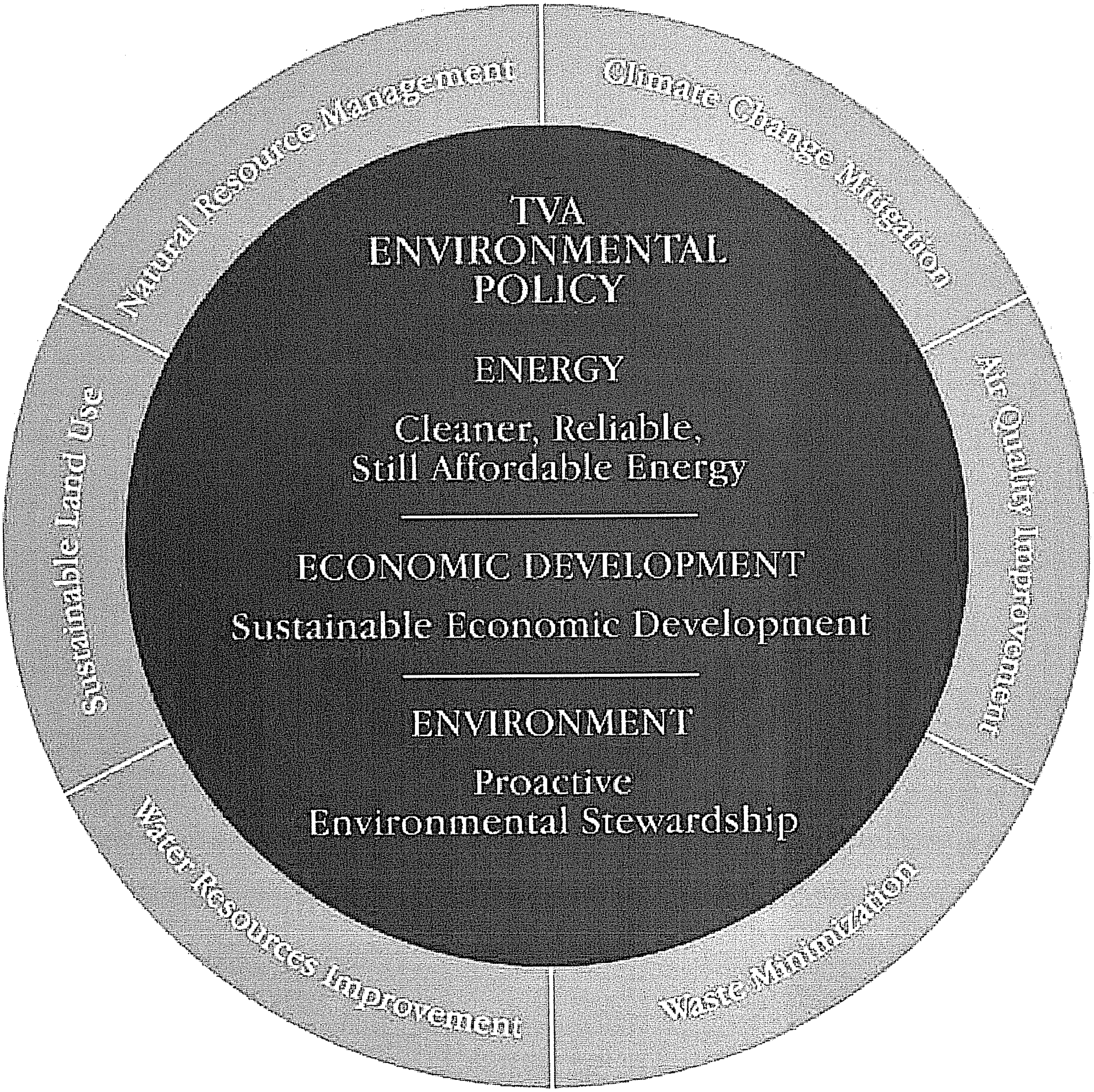
President Franklin D. Roosevelt (seated) signs the Tennessee Valley Authority Act, creating TVA on May 18, 1933.



Trout fishing in the Clinch River near Norris Dam is just one of the many recreational amenities available to the people of the Tennessee Valley.

Construction overlook of the Norris Dam located in Anderson and Campbell Counties in Tennessee, c. mid-1930s.

TVA's Environmental Policy



1 TVA's Environmental and Energy Future

After more than two years of development, the Tennessee Valley Authority (TVA) has completed its Integrated Resource Plan (IRP), entitled TVA's Energy and Environmental Future. This IRP is the product of extensive analysis and collaboration with many of TVA's partners and stakeholders.

Many electric utilities use the integrated resource planning process as a decision tool to help define both near- and long-term challenges. For TVA, the process was expanded to consider impacts on the environment and the economy. The IRP provides guidance in choosing the best resource options to meet future energy demand by considering future uncertainties, power reliability, financial, economic and environmental impacts associated with those options.

TVA's IRP has been developed to support TVA's mission for meeting the electric power needs of the Tennessee Valley region in a sustainable manner. The 20-year strategy recommended by the IRP provides direction for decisions that require a long lead time. It is consistent with TVA's Environmental Policy and its renewed vision – *to become one of the nation's leading providers of low-cost and cleaner energy by 2020*. The renewed vision and this IRP will better equip TVA to meet the substantial challenges facing the electric utility industry for the benefit of TVA stakeholders.

1.1 TVA Overview

1.1.1 Yesterday – An Innovative Solution

TVA stands as one of President Franklin D. Roosevelt's most innovative ideas. He envisioned TVA as "a corporation clothed with the power of government but possessed with the flexibility and initiative of a private enterprise."

TVA is a federal agency and corporation, wholly owned by the people of the United States and tasked by Congress to:

- Improve the quality of life for the residents of the Tennessee Valley region
- Foster economic development
- Promote conservation and wise use of the region's natural resources

Since its inception, TVA has worked to improve the quality of life for the people who live in the TVA service area. For more than 75 years, TVA has succeeded in its unique mission of serving the region through energy, environment and economic development. TVA established integrated resource management as the means for solving the competing and often conflicting interests of its mission, such as managing the Tennessee River system for navigation, flood control, recreation and power production. While the challenges evolved and new ones developed, TVA has relied on its strategy of devising integrated solutions.

1.1.2 Today – The Mission Continues

TVA's multi-faceted mission of providing low-cost, reliable power; serving as a catalyst for economic development; protecting the environment; stimulating technological innovation and managing an integrated river system in the Tennessee Valley region is the same today as it was 78 years ago.

TVA operates the nation's largest public power system. It provides power to more than nine million people, through 155 distributors of TVA power and 56 directly served customers, in an area encompassing 80,000-square-miles, including most of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina and Virginia.

Low-Cost Power

Maintaining a diverse portfolio of generation resources helps TVA keep power rates in the Tennessee Valley competitive regionally and nationally. TVA operates 56 active coal-fired units, six nuclear units, 109 conventional hydroelectric units, four pumped-storage units, 87 simple-cycle combustion turbine units, eight combined cycle units, nine diesel generator units, one digester gas site, one wind energy site and 14 solar energy sites.[1]

[1]As of Sept. 30, 2010

A portion of TVA's electrical supply is purchased from third-party operators under long-term purchased power agreements (PPAs). This diverse supply portfolio has enabled TVA to meet the region's energy demands, reliably and at competitive prices.

While keeping prices low, TVA has maintained world-class transmission reliability. TVA's transmission system is one of the largest in North America. It efficiently delivered more than 177 billion kilowatt-hours to customers in 2010. For the past 12 years, the system has achieved 99.999 percent reliability.

Economic Development

A benefit of TVA's large power system is the ability to produce power at prices below the national average, thus attracting industry to the region and making TVA a national leader in economic development. During the past five years, TVA has helped attract or retain 265,000 jobs in its service territory and has secured more than $27 billion in capital investment for the region through its Valley Investment Initiative program.

> The Watts Bar Nuclear Plant's Unit 2 project created 3,200 construction jobs.
>
> After completion in 2013, it will provide 300 permanent jobs.

In 2010, TVA worked in partnership with state and local officials in the recruitment and/or expansion of 150 companies in the TVA service area. One of TVA's most recent economic development initiatives has been the Megasites program. Through the Megasites program, five large industrial sites were sold to Dow Corning/Hemlock Semiconductor, Volkswagen, Paccar, Toyota and SeverCorr.

Environmental Stewardship

TVA's environmental stewardship (non power) programs include managing the Tennessee River and approximately 293,000 acres of reservoir lands to protect natural resources, to enhance economic development, and to provide recreational opportunities, adequate water supply and improved water quality within the Tennessee Valley watershed.

TVA's Environmental Policy provides objectives for an integrated approach related to providing cleaner, reliable and affordable energy, supporting sustainable economic growth, and engaging in proactive environmental stewardship. The Environmental Policy provides additional direction in several environmental stewardship areas, including air quality improvement, climate change mitigation, water resource protection and improvements, sustainable land use and natural resource management.

Aligning with the objectives of the Environmental Policy and TVA's renewed vision, TVA is committed to continue minimizing the environmental impacts of its operations. In 1995, TVA was the first utility in the nation to participate in a voluntary greenhouse gas reduction program sponsored by the U.S. Department of Energy. As a result, TVA has reduced or avoided more than 305 million tons of carbon dioxide (CO_2) from being emitted into the atmosphere.

Today, air quality across the region is the best it has been in more than 30 years. Since 1977, TVA has spent more than $5 billion on clean air controls. The controls have reduced sulfur dioxide (SO_2) emissions by 82 percent and nitrogen oxide (NO_x) emissions by nearly 86 percent from 1990 levels.

Technological Innovation

TVA is also committed to technological innovation. In 2000, TVA developed the first wind farm in the Southeast, and five of today's 14 solar photovoltaic sites were constructed for its green power pricing program, Green Power Switch®. In 2001, the program was expanded to include methane co-firing at Allen Fossil Plant in Memphis, Tenn.

Recently, TVA partnered with Nissan North America, the State of Tennessee, the Electric Transportation Engineering Corporation and local distributors to develop a plan to deploy electric vehicle charging stations. In January 2011, TVA and the Electric Power Research Institute unveiled an electric vehicle charging station that can make electricity from sunlight, store it and put it back in the power grid when needed.

Integrated River Management

TVA has remained focused on its mission to manage the nation's seventh-largest river system. TVA works constantly to balance energy production, navigation, flood control, recreation and water supply to provide multiple benefits from its management of the river system and associated public lands. In an average year, TVA prevents about $240 million in flood damage in the Tennessee Valley region and along the Ohio and Mississippi rivers.

TVA Customers

TVA delivers electricity to three main customer groups–local utilities (distributors of TVA power), directly served customers and off-system customers. A priority for TVA is to serve customers by meeting their needs in a reliable, responsible manner. Partnership with the distributors of TVA power is crucial in the delivery of low-cost, reliable power to end-use customers.

Distributors of TVA power comprise the bulk of TVA's customer base and are the backbone of the region's power distribution system. Accounting for roughly 81 percent of total

TVA sales and 87 percent of total TVA revenue, the distributors consist of municipally-owned and consumer-owned utilities. TVA generates and delivers electricity to the local utilities, which deliver electricity to their residential, commercial and industrial end-use customers. Municipal distributors comprise the largest block of TVA customers. Many of the consumer-owned cooperative utilities were formed to bring electricity to then-sparsely populated rural, remote areas of the Tennessee Valley region.

Large industries and federal installations, such as Oak Ridge National Laboratory, that buy electricity directly from TVA, account for 19 percent of total sales and 13 percent of TVA's total revenue. The remainder of TVA's sales and revenue comes from off-system customers that buy power from TVA on the interchange market.

TVA power contracts govern the relationships between TVA and the distributors of TVA power, including the pricing structure under which power is sold. These contracts provide for distributors' total power requirements, meaning TVA agrees to generate and deliver enough electricity to meet the distributors' full electric load, including reserves, both now and in the future.

1.1.3 Future – A New Era

In the face of challenging economic conditions, tougher emissions standards, an aging generating fleet and emerging customer needs, TVA needed to examine its strategic direction. In August 2010, TVA President and Chief Executive Officer, Tom Kilgore, announced a renewed TVA vision. The renewed vision is the first step toward establishing a new strategic direction for TVA.

TVA's renewed vision – to become one of the nation's leading providers of low-cost and cleaner energy by 2020 – will help the region and the nation achieve a cleaner energy future. The vision has three components:

1. To be the nation's leader in improved air quality
2. To be the nation's leader in increased nuclear production
3. To be the Southeast's leader in increased energy efficiency

> In support of the renewed vision, TVA plans to idle nine coal-fired units (1,000 MW) over the next five years.

TVA will work to achieve this vision while being dedicated to improving its core business of low rates, high reliability and responsibility.

1.2 Looking Ahead

1.2.1 Bridging the Gap

TVA undertook the IRP process at a critical time. Nationally, there is a consensus that energy should be produced in cleaner ways—a direction that TVA has embraced in specific goals set forth in its environmental policy and renewed vision. Achieving these goals and keeping electricity affordable is a significant challenge. Analyses of stakeholder concerns, operational constraints and the trade-offs necessary to develop an acceptable long-term solution make the challenge particularly difficult, especially when coupled with the recovering economy and regulatory uncertainty facing the utility industry.

TVA last completed an Integrated Resource Plan, entitled *Energy Vision 2020* (EV2020), in 1995. EV2020 was a comprehensive assessment of alternative strategies developed for meeting future electricity needs through 2020 based on projected future conditions in the Tennessee Valley region.

While EV2020 accurately reflected the challenges, forecasts and opportunities at the time of publication, significant changes in the industry and changing customer demand called for a fresh analysis and plan.

This IRP was built from the foundation established in EV2020, incorporates changes that have transpired and will ensure the best possible solutions are implemented for TVA and its stakeholders.

1.2.2 Challenges Facing TVA

The size of TVA's power system and its influence on the region's economy, environment and resources make integrated resource planning significant to the public it serves. The competitive success of businesses and industries, as well as the ability to sustain and improve the quality of life for the millions served by TVA electricity, are significantly impacted by the decisions that will be guided by the results of the IRP process.

Electricity cannot yet be stored economically in meaningful quantities, so the supply of electricity must constantly be balanced with the demand. Therefore, electricity providers such as TVA must project the future demand and take the necessary steps to meet the forecasted demand. This involves the construction of generating capacity and the procurement of purchased power. Given the long lead times required to plan, permit and build generating facilities, demand forecasts involve 10- to 20-year outlooks.

Effective transmission is usually a cost-effective means of providing power system flexibility and reliability. However, potential effects on water, vegetation, wildlife and other environmental concerns make this an option that must be carefully evaluated.

Transmission expansion also requires long lead times and is a vital component in meeting forecasted demand. It is particularly necessary to acquire renewable energy, which tends to be located outside TVA's service area and is intermittent in nature.

In addition to building generating facilities and purchasing power from independently owned facilities through long-term contracts, TVA and distributors of TVA power can meet demand by deploying programs that encourage energy efficiency and reduce demand during daily periods of peak power use. These activities entail associated uncertainty and risk that must be managed to ensure reliability.

Designing and executing an effective strategy is a major planning challenge for all electric utilities. TVA meets the challenge by working with stakeholders to design a long-term resource plan that recognizes the choices that must be made to achieve a common goal of an affordable, clean and reliable supply of electricity.

1.3 Integrated Resource Planning

1.3.1 Role of the Integrated Resource Plan

Integrated resource planning is a crucial element for success in a constantly changing business and regulatory environment and is based on comprehensive, holistic and risk-aware analysis. The integrated approach considers a broad spectrum of feasible supply- and demand-side options and assesses them against a common set of planning objectives and criteria, including environmental impact.

The IRP objective is to help meet future customer demand by identifying the need for generating capacity and determining the best mix of resources to fill the need. The capacity gap is the difference between the projected firm (or known) requirements and existing firm supply.

The following strategic principles guided development of this IRP:

- Mitigate risk at a reasonable cost
- Balance generation resources to reduce supply and price risk
- Balance production and load
- Minimize environmental impacts of the portfolios
- Provide incentives to customers to optimize the load factor
- Provide flexibility to adapt to changing market conditions and future uncertainty

- Improve credibility and image through a comprehensive, balanced and transparent approach
- Integrate perspectives of internal and external stakeholders throughout the process

1.3.2 Integrated Resource Planning Process

Instead of one correct answer, this IRP entails a robust, "no-regrets" plan that balances competing objectives while reducing costs and risks and retaining the flexibility to respond to future risks and opportunities.

This IRP was framed to assess future demand and the cost and quantity of future supply options. Therefore, forecasts of various inputs (e.g., inflation, commodity prices and environmental regulations) were simultaneously evaluated. Constraints (e.g., corporate strategic and environmental objectives) were considered as different combinations of strategies and futures were analyzed and evaluated. Afterward, additional extensive computer modeling, analyses, public input, reviews and dialogue with TVA's leadership led to the consideration of strategic alternatives.

"No-regrets" is a plan that best balances competing objectives while reducing costs and risk and retaining the flexibility to respond to future risk and opportunities as they unfold.

TVA recognizes that the future is uncertain and that forecasts and stakeholder concerns can change. To take advantage of updated information and encourage ongoing public involvement in defining the region's future energy needs, TVA is committed to begin the next IRP effort by 2015.

1.4 IRP Deliverables

1.4.1 Draft and Final IRP Documents

The Draft IRP was released Sept. 15, 2010, for public review and comment. It provided a broad look at all options considered by TVA and the long-term implications of various business strategies.

The final IRP recommends a robust, flexible strategy that supports TVA's renewed vision. The Recommended Planning Direction entails an outcome that balances costs, efficiency in electricity generation, reliability, energy efficiency, environmental responsibility and competitive prices for customers.

1.4.2 Natural Resource Plan

Since the June 15, 2009, publication of the IRP Notice of Intent, TVA determined that planning processes for the Environmental Policy goals that are not closely tied to energy production and consumption would be better addressed in a separate study.

Therefore, a Natural Resource Plan will evaluate the implementation of TVA's reservoir lands planning, natural resource management, water resources management and recreation processes and strategies. The content of the accompanying environmental impact statement will be consistent with TVA's Environmental Policy, TVA's Land Policy, the previous Shoreline Management Initiative Environmental Impact Statement and the Reservoir Operations Study Environmental Impact Statement.

1.4.3 Draft and Final Environmental Impact Statement

As a federal agency, TVA must comply with the National Environmental Policy Act of 1992 (NEPA). The act requires all federal agencies to consider the impact of its proposed actions and alternatives on the environment before making decisions with potential environmental impacts. The NEPA process provides a structured means for analyzing competing options and for involving the public in TVA's decision-making process. The primary product from the NEPA process is an environmental impact statement (EIS).

Even though the IRP and the associated EIS were combined into one document for EV2020, they are published as two separate documents for this IRP. The components of the associated EIS were incorporated into the overall integrated resource planning process. This provided a preferred resource plan that focuses on reducing costs and risk while improving TVA's environmental performance.

TVA chose to develop a programmatic level EIS as opposed to a project- or site-specific document because of the broad nature of integrated resource planning.

As part of the final IRP, TVA prepared an associated EIS in accordance with the NEPA 42 USC §§ et seq., Council on Environmental Quality regulations for implementing NEPA.

1.5 IRP Outline

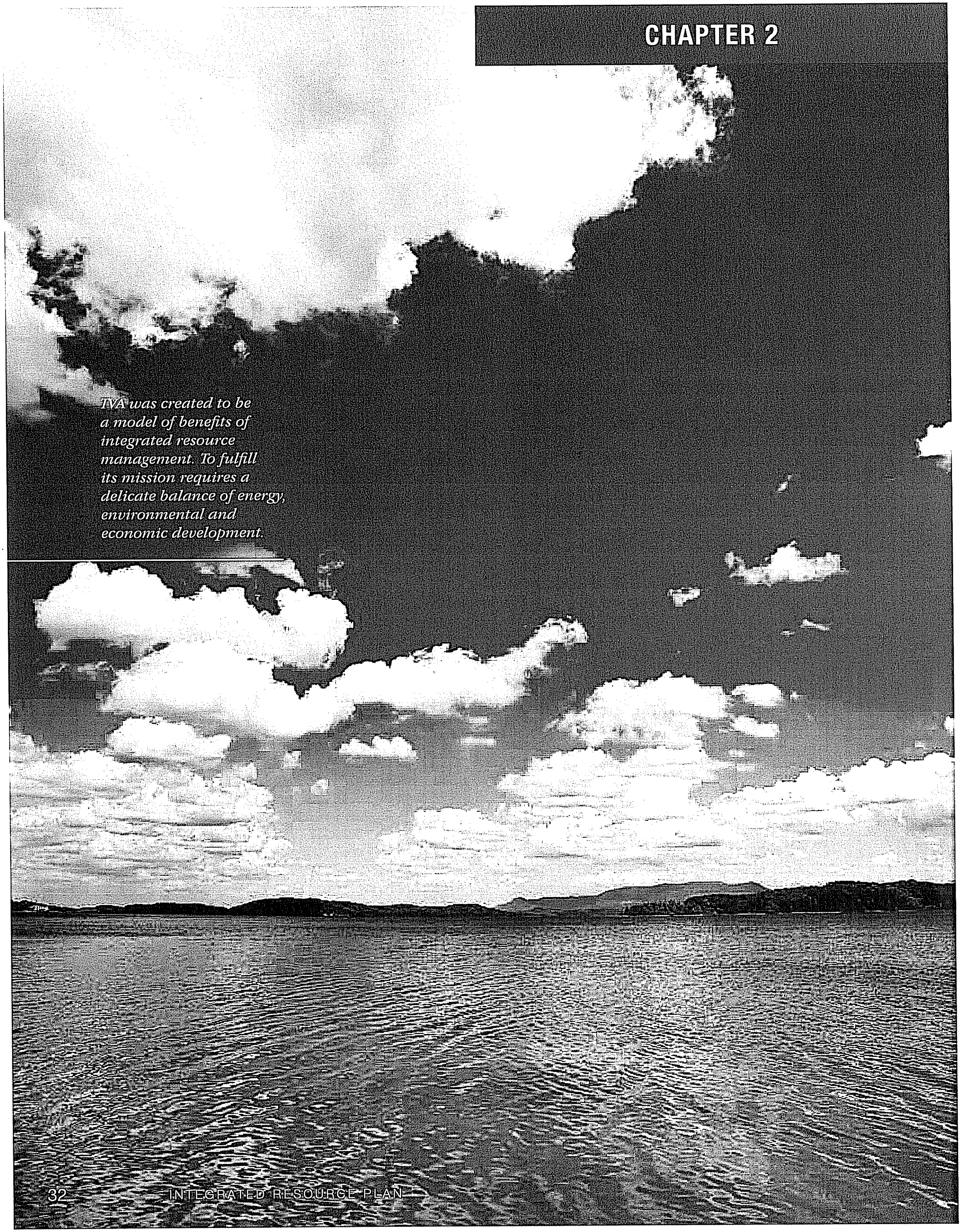
This IRP consists of nine chapters and six appendices.

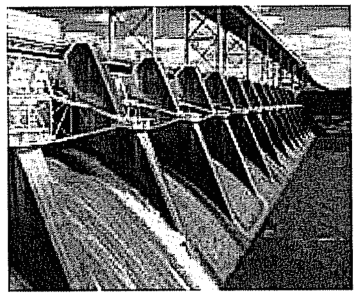
Chapter 1	TVA's Environmental and Energy Future – history of TVA, TVA overview, looking ahead, the IRP's role and purpose, the goals and objectives of this IRP, the overall process, release of the Draft IRP and the associated EIS, incorporation of public input and IRP deliverables
Chapter 2	IRP Process – seven distinct steps of the IRP process and how public participation was incorporated in each step
Chapter 3	Public Participation – public participation components during this IRP process and summary of the valuable input received
Chapter 4	Need for Power Analysis – TVA's need for power analysis, TVA power supply, base-load, intermediate, peaking, storage resources and TVA's generation mix
Chapter 5	Energy Resource Options – potential supply- and demand-side options for future TVA power portfolios
Chapter 6	Resource Plan Development and Analysis – overview of scenario and strategy development, key uncertainties that defined the scenarios, planning strategies, portfolio development, planning strategy scorecard (including ranking and strategic metrics), scorecard calculation and planning strategy evaluation
Chapter 7	Draft Study Results – results from the Draft IRP analysis which includes the identification of the preferred planning strategies
Chapter 8	Final Study Results and Recommended Planning Direction – results from the final IRP study which includes the identification of the Recommended Planning Direction
Chapter 9	Next Steps – identifies next steps and recommendations
Appendix A	Method for Computing Environmental Metrics – process and results from the analysis used to determine the impact of the Recommended Planning Direction on the TVA environment
Appendix B	Method for Computing Economic Impact Metrics – process and results from the analysis used to determine the impact of the Recommended Planning Direction on the TVA economy
Appendix C	Energy Efficiency and Demand Response – process used to develop EEDR portfolio used in the Draft IRP and final analysis for the Recommended Planning Direction
Appendix D	Development of Renewable Energy Portfolios – process used to develop the renewables portfolio used in the Draft IRP and the final analysis for the Recommended Planning Direction
Appendix E	Draft IRP Phase Expansion Plan Listing – 20-year expansion plans for each strategy evaluated during the Draft IRP analysis
Appendix F	Stakeholder Input Considered and Incorporated – comments were reviewed in detail and input was incorporated

TVA's Environmental and Energy Future

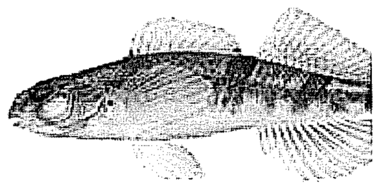
CHAPTER 2

TVA was created to be a model of benefits of integrated resource management. To fulfill its mission requires a delicate balance of energy, environmental and economic development.

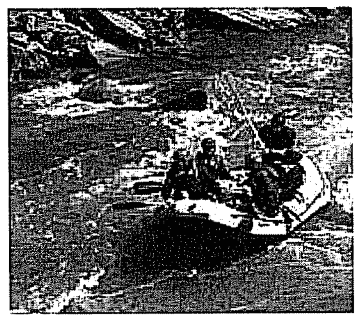




Water spills over the Fort Loudon Dam in Loudon County, Tennessee.

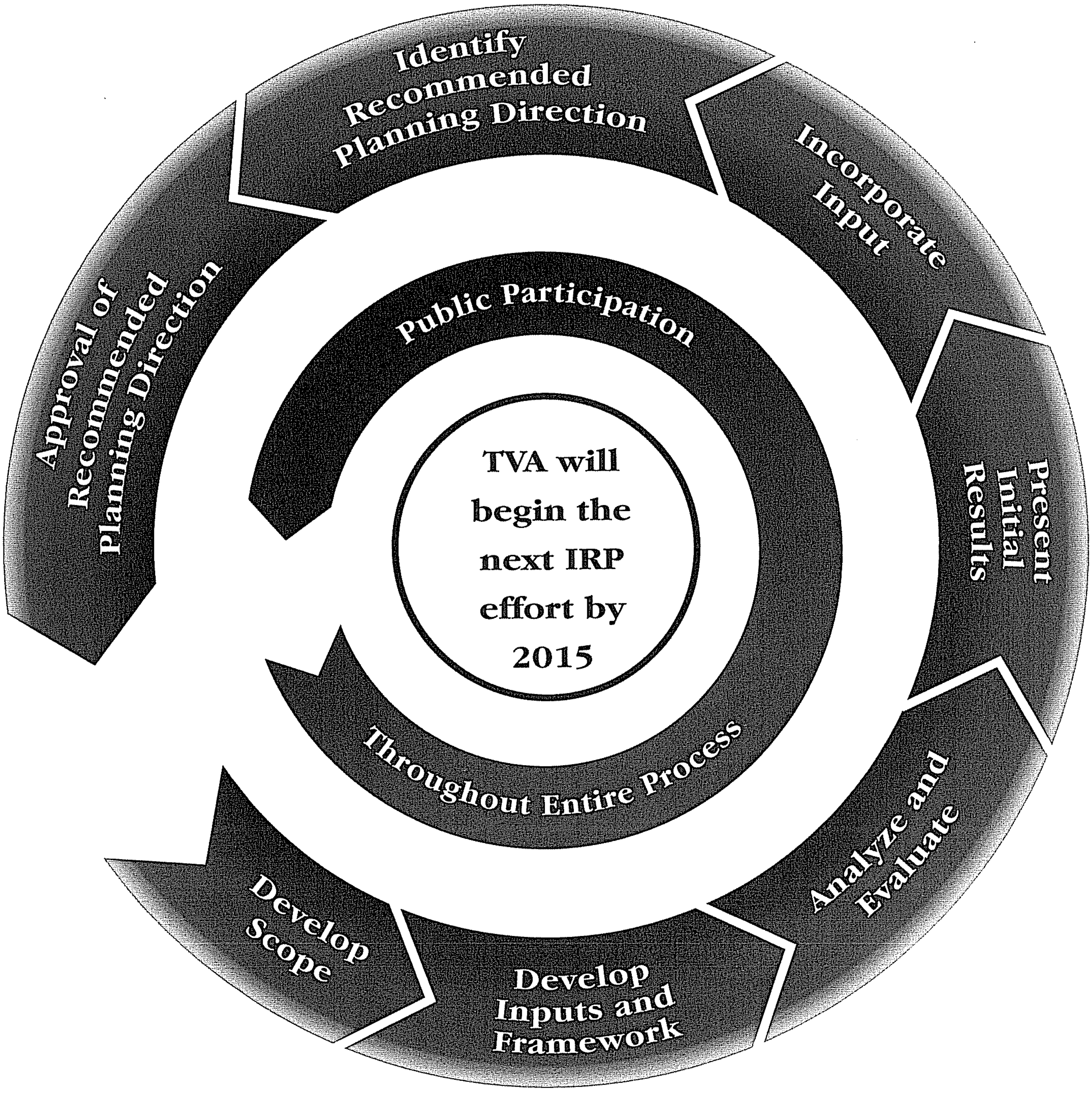


The once-endangered Snail Darter, native to rivers of the Tennessee Valley, is now thriving due in large part to the conservation efforts of TVA.



Enthusiasts enjoy white-water rafting down the Ocoee River in Polk County, Tennessee.

The IRP Process



2 IRP Process

The IRP process to develop the Recommended Planning Direction was extensive. More than two years were dedicated to discuss needs, wants, advantages, challenges, constraints, trade-offs and compromises required to develop a plan of this magnitude. A wide range of stakeholders were involved in this process, representing the general public, distributors of TVA power, industry groups, academia and research professionals and TVA leadership.

This IRP represents a significant investment by TVA to understand the needs of the people it serves and how to address those needs in a cost-effective, reliable manner. TVA believes in this process and has committed to begin the next IRP effort by 2015.

To fully appreciate the scope of TVA's IRP process, the road to producing the final IRP must be understood. TVA's IRP process consisted of the following seven distinct steps:

1. Develop scope
2. Develop inputs and framework
3. Analyze and evaluate
4. Present initial results
5. Incorporate input
6. Identify Recommended Planning Direction
7. Approval of Recommended Planning Direction

Public participation was included in each step of the process and is explained in more detail in Chapter 3 – Public Participation. The process for steps two through six are described in more detail in Chapter 6 – Resource Plan Development and Analysis. Step seven, approval of Recommended Planning Direction, is described in Chapter 8 – Final Study Results and Recommended Planning Direction.

2.1 Develop Scope

In June 2009, TVA began a public scoping period. Public scoping comments addressed a wide range of issues, including the nature of the integrated resource planning process, preferences for various types of power generation, increased energy efficiency and demand response (EEDR) and the environmental impacts of TVA's power generation. The comments received helped TVA identify issues that were important to the public.

2.2 Develop Inputs and Framework

When faced with a challenge like planning the power system for the next 20 years, a "no-regrets" decision-making framework is generally the best approach. A "no-regrets" framework is one in which decision makers utilize the best possible information available to them. This allows them to weigh the likelihood and consequence of the risks and challenges that could surface so that decisions have a high likelihood of being sound in many possible states of the world. In order to facilitate a "no-regrets" decision-making framework, TVA employed a scenario planning approach in the development of this IRP.

Scenario planning provides an understanding of how near-term and future decisions would change under different conditions. This allows for impacts on different courses of action to be effectively analyzed. These actions are then assessed to determine their performance in each and every scenario as well as their relative performance in all scenarios.

Future decisions that produce similar results across different conditions may imply that these decisions provide more predictable outcomes, whereas decisions that result in major differences are less predictable and therefore more "risky."

TVA began this process in collaboration with the Stakeholder Review Group (SRG) and developed a set of resource planning strategies that would be analyzed within the framework of this IRP.

These resource strategies represent decisions that TVA has control over (e.g., asset additions, idling coal-fired capacity, integration of more flexible resource options), whereas the scenarios, which are described in more detail below, represent aspects that TVA has no control over (e.g., more stringent regulations, fuel prices, construction costs).

Strategies represent future business decisions that TVA can make and has full control over.

Scenarios represent future conditions that TVA cannot control.

A portfolio is the intersection of a strategy and a scenario and represents a multiyear resource plan detailing how TVA intends to meet future load growth.

Different mixes of resource options (i.e., supply-side generating technologies and demand-side programs) formed the framework for distinct resource planning strategies and were designed to allow for flexible resource selection over the intended duration of the IRP planning horizon. Significant expert input was incorporated to ensure the feasibility of the elements of each planning strategy.

To facilitate a "no-regrets" analysis of the strategies developed above, TVA developed a series of scenarios to analyze the various outcomes of the resource planning strategies.

These scenarios differed from each other in several key areas, such as projected customer demand, future economic conditions, fuel prices, regulatory frameworks and numerous other key drivers. Like the strategies, these scenarios were also developed in collaboration with the SRG.

The goal of defining scenarios was to identify sets of potential events, forecasts and other important drivers that TVA cannot directly control, but that would have a direct impact on TVA's ability to achieve the goals of this IRP.

One way to think of scenarios is as miniature models of the future. In one model, the economy might stagnate, prices drop and electricity demand remains flat. In another, strong economic recovery could pressure fuel prices, drive interest rates higher, lead to rapid recovery in electricity sales and long-term demand growth and put pressure on the cost of building generating assets. Both scenarios present dramatically different challenges to any one resource strategy.

Therefore, the key to sound resource planning is designing a strategy that performs reasonably well in all scenarios, regardless of which scenario best captures the actual state of the world in the future.

Seven scenarios were initially developed. Each resource planning strategy was tested within the seven scenarios for performance. The seven scenarios and five strategies are explained in detail in Chapter 6 – Resource Plan Development and Analysis.

2.3 Analyze and Evaluate

After the scenarios and strategies were developed, detailed analysis was undertaken for each planning strategy within each of the scenarios. This phase of the IRP employed industry standard capacity expansion planning and production cost modeling software to develop total cost estimates of each planning strategy in each scenario. Other metrics, including near-term rate impacts, risks and environmental footprint, were also developed using model outputs.

TVA analyzed the hypothetical performance on the cost, risk and environmental footprint of each strategy based on the assumption that the future unfolds in a manner that resembles the specifics of each scenario.

A total of 35 unique capacity expansion plans or "portfolios" were developed for each of the seven scenarios specific to each of the five strategies. Each portfolio represented a long-term, least-cost plan of different asset mixes (both supply- and demand-side assets) that can be deployed to meet the power needs of the region.

Each portfolio was ranked using selected metrics within the framework of a consistent, standard scorecard. Special care was also taken to note not only those portfolios that performed best overall, but also those portfolios that performed well in most states of the future (a key requirement for a "no-regrets" portfolio development). The metrics used were chosen based on their importance and centrality to TVA's mission and included measures for capturing financial (e.g., cost and risk), economical and environmental impacts.

The ranking was not intended to identify any single portfolio as "the best" in recognition of the fact that a portfolio with the highest overall score may not have performed as well as other portfolios across multiple scenarios. In other words, portfolios were analyzed for their robustness under stress across multiple scenarios, as opposed to overall performance in total. This was an important step since metrics alone could signify good performance in one or two future states of the "world," but average or poor performance in all others.

The process of a consistent analytical ranking exercise provided TVA's Board of Directors and leadership team with information that was used to help conduct evaluations of decisions pertaining to TVA's existing generation fleet and available generation options. It also facilitates TVA's ultimate adoption of a long-term resource planning strategy that will serve as a foundation for TVA's near-term business and financial plans.

2.4 Present Initial Results

For this phase of the IRP process, TVA presented the results of the Draft IRP and the associated EIS to both internal TVA management and the general public. The Draft IRP outlined alternative strategies that TVA considered, but did not include an exhaustive list of all strategies that were analyzed. However, it did include a sampling of unique strategies that represent a broad spectrum of viable options for implementation.

As in the scoping period, TVA encouraged public comments on the Draft IRP and the associated EIS. The comments received enabled TVA staff to identify public concerns and recommendations concerning the future operation of the TVA power system.

The public comment period began in October 2010 with the EPA's publication of the Notice of Availability of the Draft IRP and associated EIS in the Federal Register.

During the public comment period, TVA held five public meetings to provide information about this IRP as well as the opportunity to provide input to TVA staff.

TVA addressed all substantive comments received during the public comment period in the final IRP and the associated EIS.

2.5 Incorporate Input

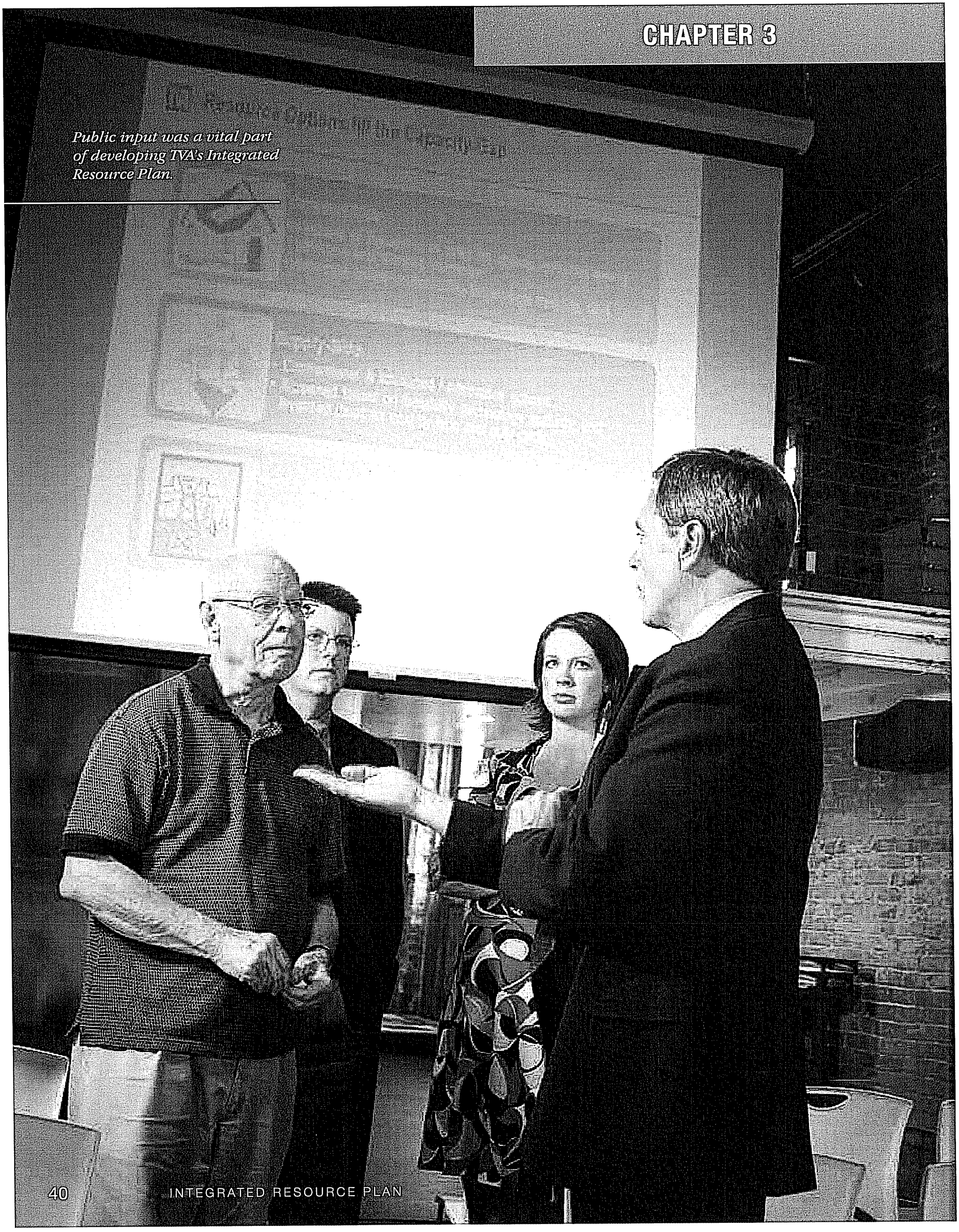
The public comment period ended Nov. 15, 2010. TVA received approximately 500 comments. All comments were reviewed in detail and synthesized into key points that required a response. Comments were logged into a comment management database for tracking purposes and assigned to an appropriate subject-matter expert. An extensive inventory of responses is included in the associated EIS.

2.6 Identify Recommended Planning Direction

After review of the public comments received and additional analysis, TVA staff identified a Recommended Planning Direction to present to TVA's Board of Directors. The Recommended Planning Direction is based on a number of key criteria, as mentioned above, and is intended to serve as a guide for implementation of TVA's planning objectives.

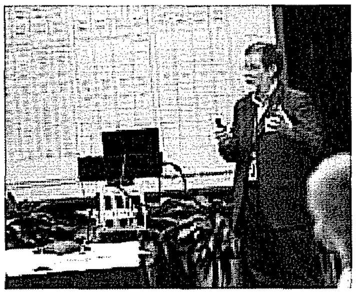
2.7 Approval of Recommended Planning Direction

No sooner than 30 days after the Notice of Availability of the associated EIS is published in the Federal Register, the TVA Board of Directors will be asked to approve the Recommended Planning Direction. The TVA Board of Directors' decision will be described and explained in a Record of Decision.



Public input was a vital part of developing TVA's Integrated Resource Plan.

Public Participation



Through public meetings, webinars and various forms of gaining insight from the people we serve, TVA was able to integrate their ideas and concerns into the plan.

Stakeholder Review Group

Lance Brown, Executive Director
Partnership for Affordable Clean Energy
Montgomery, Alabama

Dana Christensen, Associate Director
Oak Ridge National Laboratory
Oak Ridge, Tennessee

Ryan Gooch, Director, Energy Policy
Tennessee Dept. of Economic & Community Development
Nashville, Tennessee

Louise Gorenflo, TVA Committee Chair
Sierra Club
Crossville, Tennessee

Richard Holland, Vice President
Tennessee Paper Council
Nashville, Tennessee

Tom King, Director for Energy Efficiency & Electricity Technologies Program
Oak Ridge National Laboratory
Oak Ridge, Tennessee

George Kitchens, General Manager
Joe Wheeler Electric Membership Corporation
Trinity, Alabama

Henry List, Deputy Secretary
Kentucky Energy and Environment Cabinet
Frankfort, Kentucky

David McKinney, Environmental Services Division Chief
Tennessee Wildlife Resource Agency
Nashville, Tennessee

Jerry Paul, Distinguished Fellow on Energy Policy
Howard Baker, Jr. Center for Public Policy
Knoxville, Tennessee

David Reister
Environmental Stakeholder
Knoxville, Tennessee

Jan Simek, Professor of Science
University of Tennessee
Knoxville, Tennessee

Jack Simmons, President and CEO
Tennessee Valley Public Power Association
Chattanooga, Tennessee

Stephen Smith, Executive Director
Southern Alliance for Clean Energy
Knoxville, Tennessee

Lloyd Webb
Tennessee Valley Industrial Committee
Cleveland, Tennessee

Deborah Woolley, President
Tennessee Chamber of Commerce and Industry
Nashville, Tennessee

TVPPA believes the overall process TVA used in conducting the IRP was sound, transparent and that it afforded opportunity for external input to TVA from the public and the other stakeholders.

— Jack Simmons, President and CEO
Tennessee Valley
Public Power Association

TVA's current planning process, including the formation of the Stakeholder Review Group, is a significant step forward not only for TVA's planning processes, but also for TVA's relationship with the nine million people it serves.

— Stephen Smith, Executive Director
Southern Alliance for Clean Energy

TVA wanted to demonstrate transparency by including the public as much as possible during the IRP process. For example, the need for a Stakeholder Review Group was an outcome of the seven public meetings held last summer.

— Randy Johnson, Manager
Integrated Resource Planning
Tennessee Valley Authority

3 Public Participation

TVA is the largest public power company in the nation. An objective of this IRP was to understand the needs of the people it serves and how to address those needs in a cost-effective, reliable manner. Since the needs of the people vary, some people are more concerned about the cost of power, some on reliability, while others are concerned about environmental impacts. Therefore, it is TVA's ultimate responsibility to balance these competing needs as it plans for the future.

A transparent and participatory approach was utilized in the development of this IRP. Many opportunities were available to the public that influenced the development – and ultimately the outcome – of this IRP. For example, public briefings and meetings were held across the region, and an advisory review group was created. The following key objectives of public involvement were:

- Engage numerous stakeholders with differing viewpoints and perspectives throughout the entire IRP process
- Incorporate public opinions and viewpoints into the development of the IRP, including activities and opportunities for stakeholders to review and comment on various inputs, analyses and options considered
- Encourage open and honest communication in order to facilitate a sound understanding of the process
- Provide multiple communication channels to provide several ways for members of the public to learn about the IRP process and to provide input

TVA involved the public in each critical step of the IRP process. The involvement helped TVA identify the most effective ways to serve the people of the Tennessee Valley region. Public participation was actively solicited three times during the IRP process.

1. Public scoping period
2. Analysis and evaluation period
3. Draft IRP public comment period

3.1 Public Scoping Period

The TVA IRP process began with a 60-day public scoping period June 15, 2009. TVA announced the start of the process in newspapers throughout the region via media releases and on TVA's website.

In addition, the EPA published the official EIS Notice of Intent in the Federal Register. This notice is required by the NEPA guidelines which require federal agencies such as TVA to prepare an EIS whenever its actions, such as the development of an IRP, have the potential to affect the environment.

Public Comment Process:

Step 1 - Public Scoping Period

- Public Meetings
- Written Comments
- Scoping Questionnaire

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

During the scoping period, TVA disseminated a broad range of information to the public, including the reasons for developing an IRP, what it would focus on, the process for how an IRP is developed and how the results will be used to guide strategic decision making. Public scoping provided an early and open process to ensure:

- Stakeholder issues and concerns were identified early and properly studied
- Reasonable alternatives and environmental resources were considered
- Key uncertainties that could impact costs or performance of certain energy resources were identified
- Input received was properly considered and would lead to a thorough and balanced final IRP

TVA also reiterated the need to have a balanced approach when considering the tradeoffs of one energy resource for another. While developing this IRP, TVA sought public input on a variety of issues and asked the following questions:

- How will any changes affect system reliability and the price of electricity?
- Should the current power generation mix (e.g., coal, nuclear power, natural gas, hydro, renewable) change?

- Should energy efficiency and demand response be considered in planning for future energy needs?
- Should renewables be considered in planning for future energy needs?
- How can TVA directly affect electricity usage by consumers?

The scoping period helped shape the initial development and framework of this IRP. TVA used the input received to determine what resource options should be considered to meet future demand. TVA used two primary techniques, public meetings and written comments, to collect public input during the scoping period.

3.1.1 Public Meetings

During the scoping period, TVA held seven public meetings across the Tennessee Valley between July 20 and Aug. 6, 2009 (Figure 3-1). The meetings were conducted in an informal, open house format to give participants an opportunity to express concerns, ask questions and provide comments. Exhibits, fact sheets and other materials were available at each public meeting to provide information about the Draft IRP and the associated EIS.

Date	Location
July 20, 2009	Nashville, Tenn.
July 21, 2009	Chattanooga, Tenn.
July 23, 2009	Knoxville, Tenn.
July 28, 2009	Huntsville, Ala.
July 30, 2009	Hopkinsville, Ky.
Aug. 4, 2009	Starkville, Miss.
Aug. 6, 2009	Memphis, Tenn.

Figure 3-1 – Public Scoping Meetings

Attendees included members of the general public, representatives from state agencies and local governments, TVA's congressional delegation representatives, distributors of TVA power, non-governmental organizations and other special interest groups.

Approximately 200 attended the public scoping meetings. TVA subject-matter experts attended each meeting to discuss issues and respond to questions about the IRP planning process and TVA's power system and programs.

3.1.2 Written Comments

During the scoping period, TVA accepted comments via email, fax, letters, TVA's website, public scoping meetings and a scoping questionnaire. At the public scoping meetings, verbal comments were recorded by court reporters and attendees were able to submit written comments by logging onto TVA's website using TVA supplied computers.

Overall, TVA received approximately 1,000 comments from the following communication tools:

- Scoping questionnaire
- Email
- TVA's website
- Public meetings

Comments were received from four federal agencies and 20 state agencies representing six of the seven TVA region states. Some of these responses included specific comments, while others stated they had no comments, but asked to review the Draft IRP and the associated EIS. Figure 3-2 shows the distribution of scoping comments by geographic area.

Some agencies, organizations and individuals provided comments specific to TVA's natural and cultural resource stewardship activities. These comments were not included in the scoping report because they focused on another planning process – TVA's Natural Resource Plan (NRP) and associated EIS. The full scoping report on this IRP as well the NRP can be found on TVA's website.

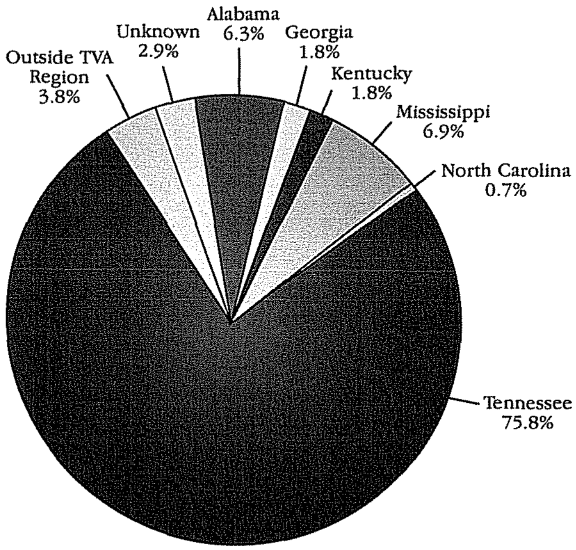


Figure 3-2 – Distribution of Scoping Comments by Geographic Area

3.1.3 Scoping Questionnaire

An 11-part scoping questionnaire was distributed at public meetings and made available on TVA's website. The questionnaire was developed to elicit public opinion on TVA's future generation and efficiency options. At least part of the scoping questionnaire was completed by 845 people, and 640 of the respondents answered the write-in questions as well as the multiple-choice questions.

Many of those who completed the questionnaire expressed a willingness to take various measures to reduce their energy use or pay higher rates for cleaner energy. The willingness to undertake some measures increased with the availability of financial incentives.

After further analysis, the results of the questionnaire indicated that the findings were not statistically significant and the survey population was not fully representative of the entire Tennessee Valley region. Therefore, TVA decided to conduct a phone survey of approximately 1,000 individuals across the entire region in the summer of 2010.

3.2 Analysis and Evaluation Period

The analysis and evaluation period took key themes and results identified from the scoping period and developed the framework for analysis and evaluation. The findings were considered when TVA developed the range of strategies for IRP analysis.

During this phase, TVA used the following three techniques to collect public input:

1. Stakeholder Review Group
2. Public briefings
3. Phone survey

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

- Stakeholder Review Group
- Public Briefings
- Phone Survey

Step 3 - Draft IRP Public Comment Period

3.2.1 Stakeholder Review Group

Early in the IRP process, TVA recognized it would be difficult to get specific and continuous input from the public beyond the scoping period. To obtain more in-depth, ongoing input from the public, TVA established an advisory Stakeholder Review Group (SRG) in July 2009.

The formation of this diverse 16-member review group (listed on page 42) was the cornerstone of the public input process. It consisted of representatives from business and industry, state agencies, government, distributors of TVA power, academia, special interest groups and civic organizations. In addition to providing their individual views to TVA, SRG members represented their constituency and reported to them on the IRP process.

The SRG met approximately every month with TVA. Ten meetings were held prior to the release of the Draft IRP and the associated EIS at various locations throughout the region. Five additional meetings were held between the release of the Draft IRP and approval of the Recommended Planning Direction to facilitate ongoing feedback and guidance for this IRP. Figure 3-3 shows the dates and locations of all the SRG meetings.

Date	Location
July 29, 2009	Nashville, Tenn.
Aug. 18, 2009	Knoxville, Tenn.
Sept. 24, 2009	Chattanooga, Tenn.
Oct. 22 & 23, 2009	Chattanooga, Tenn.
Dec. 10 & 11, 2009	Nashville, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.
June 29, 2010	Murfreesboro, Tenn.
July 20 & 21, 2010	Chattanooga, Tenn.
Aug. 12, 2010	Chattanooga, Tenn.
Aug. 26, 2010	Chattanooga, Tenn.
Oct. 28, 2010	Knoxville, Tenn.
Nov. 18, 2010	Murfreesboro, Tenn.
Dec. 15, 2010	Chattanooga, Tenn.
Jan. 26, 2011	Knoxville, Tenn.
Feb. 24, 2011	Chattanooga, Tenn.

Figure 3-3 – Stakeholder Review Group Meetings

The meetings were designed to encourage dialogue on all facets of the IRP process, and to facilitate information sharing, collaboration and expectations for this IRP. Topics included energy efficiency best practices, TVA's power delivery structure, load and commodity forecasts and supply resource options.

The individual views of SRG members were collected on the entire range of assumptions, analytical techniques and proposed energy resource options and strategies. Given the diverse makeup of the SRG, there were a wide range of views on specific issues, such as the value of energy efficiency programs, environmental concerns and the appropriateness of some new technologies. Open discussions supported by the best available data facilitated better comprehension of the specific issues.

To increase public access and transparency to the IRP process, all non-confidential SRG meeting material (i.e., presentations, agenda and minutes) was posted on TVA's website. In addition, TVA developed an internal website specifically for SRG members to post information on and to request data from TVA staff.

3.2.2 Public Briefings

In addition to the public scoping and SRG meetings, TVA held four public briefings (Figure 3-4). The public briefings informed the general public of the IRP process.

Date	Location
Oct. 23, 2009	Chattanooga, Tenn.
Nov. 16, 2009	Chattanooga, Tenn.
Feb. 17, 2010	Knoxville, Tenn.
May 13, 2010	Knoxville, Tenn.

Figure 3-4 – Public Briefings

Participants had the option to attend in person or by webinar. The format of the public briefings included a brief presentation followed by a moderated Q&A session with the audience.

Topics discussed at the public briefings included an overview of the integrated resource planning process, resource options, development of scenarios and strategies and evaluation metrics.

The public briefings attendance averaged 15 to 20 in-person participants and approximately 30 to 40 participants by webinar. Videos of the briefings and presentation materials were posted on the IRP project website.

TVA also briefed the public on the IRP process through presentations given at local organizations, clubs and associations including the following:

- Association of Energy Engineers
- Tennessee Renewable Energy and Economic Development Council
- Chattanooga Engineers Club
- City of Chattanooga
- Chattanooga Green Spaces
- EPRI Environmental Aspects of Renewable Energy Interest Group Workshop
- Clean Energy Speakers Series at Georgia Tech
- Howard H. Baker, Jr. Center for Public Policy
- Technical Society of Knoxville

3.2.3 Phone Survey

To ensure an even wider representation of opinions on IRP choices were considered, TVA partnered with Harris Interactive to develop a statistically representative phone survey of approximately 1,000 Tennessee Valley residents. The customer phone survey was conducted during June and July 2010 for the following reasons:

- Determine primary power generation concerns among the Tennessee Valley residents (i.e., cost, reliability, use of renewables, etc.)
- Determine market potential for voluntary and financially incentivized energy efficiency programs
- Determine market potential of renewable programs, including Green Power Switch® and other existing or planned energy efficiency and demand response programs
- Estimate potential market pricing for renewable power programs, including the additional amounts Tennessee Valley residents are willing to pay each month for energy from renewable sources
- Assess Tennessee Valley residents' attitudes of and satisfaction with TVA, including analysis of the services that it provides to the Tennessee Valley

Survey results indicated that the Tennessee Valley residents have a favorable attitude of TVA, consider system reliability a critical component of utility services and want to see TVA focused on keeping prices affordable.

Key findings included:

TVA quality of service	• 94 percent of respondents agreed that providing a reliable supply of electricity is very important in assessing TVA's quality of service • 92 percent indicated that keeping electricity rates affordable is important
Meeting future energy needs	• 70 percent of respondents also deemed it very important for TVA to reduce air pollutants and emissions

Renewable energy	• 42 percent of respondents believed that adding different energy sources, such as solar and wind, into TVA resource portfolio should be emphasized the most to meet future energy needs
	• 42 percent of respondents indicated they likely would pay more for renewable energy, with the following breakdown:
	  • Those indicating they would definitely pay more would pay an average of $12.60 per month to ensure that 10 percent of their energy comes from renewable sources
	  • This same group would pay an average of $26.91 more per month to ensure that all of their energy is renewable
	  • Tennessee Valley residents indicating they would definitely or probably pay more were willing to pay $11 to $20 per month to reduce CO_2 emissions
	  • Opportunities exist for additional Green Power Switch® awareness among Tennessee Valley residents

Biggest concerns related to electricity production	• Cost and billing • Environmental impact • Quality of power supply

3.3 Draft IRP Public Comment Period

After the Draft IRP was completed in the fall of 2010, TVA provided an opportunity for the public to provide comments and give input. Following the Sept. 15, 2010 publication of the Draft IRP with EPA, a 52-day comment period was provided to solicit input about the Draft IRP from the public.

Originally set to close Nov. 8, 2010, the 45-day comment period was extended an additional seven days to accommodate several external stakeholders' requests. For this phase of the IRP process, TVA presented the results to both internal TVA stakeholders and the general public in the Draft IRP and the associated EIS.

Public Comment Process:

Step 1 - Scoping Period

Step 2 - Analysis and Evaluation Period

Step 3 - Draft IRP Public Comment Period

- Public Meetings
- Webinars
- Written Comments

TVA used the following three techniques to collect input during the Draft IRP:

1. Public meetings
2. Webinars
3. Written comments

3.3.1 Public Meetings

TVA had five meetings with the public across the Tennessee Valley region in October 2010 (Figure 3-5). These meetings gave the public an opportunity to present their views on the Draft IRP to TVA leadership and subject-matter experts.

Date	Location
Oct. 5, 2010	Bowling Green, Ky.
Oct. 6, 2010	Nashville, Tenn.
Oct. 7, 2010	Olive Branch, Miss.
Oct. 13, 2010	Knoxville, Tenn.
Oct. 14, 2010	Huntsville, Ala.

Figure 3-5 – Public Comment Period Meetings

TVA publicized the meetings and webinars by placing advertisements in major newspapers and issuing news releases prior to each meeting that many local newspapers carried. Before each of the meetings, TVA met with local reporters in each location who frequently write about TVA and the IRP process so that they, in turn, could write articles to help the public understand the IRP process and draft document.

Online advertising (i.e., announcements on TVA's Facebook page) was used to reach an even wider audience. TVA's website was also regularly updated with the latest news regarding the IRP process and logistics for each public meeting.

At each of these meetings, TVA presented an overview of the Draft IRP followed by a moderated Q&A session supported by a panel of TVA subject-matter experts. Attendees were able to address comments or questions to the panel. Attendees also had the option to submit written and verbal comments to a court reporter before or after the presentations. A transcript and video of each meeting was recorded. The presentation slides and video of the meeting in Bowling Green, Ky., and videos of each Q&A session were posted on the TVA's website.

TVA encouraged comments from the public on the Draft IRP and the associated EIS. Comments received enabled TVA staff to identify public concerns and recommendations concerning the future operation of the TVA power system. The public comments and TVA's responses are included in the associated EIS.

3.3.2 Webinars

To encourage as much participation as possible, members of the public who were not able to attend public meetings were able to participate by webinar. Attendees registered in advance and were able to access the presentation and participate in the Q&A session from personal computers.

3.3.3 Written Comments

During the 52-day public comment period, comments were submitted via TVA's website, email, U.S. mail and fax. Comments and questions recorded at each of the public meetings were also considered.

In all, TVA received approximately 500 responses from a multitude of individuals, organizations and agencies. These responses contained 748 comments of which 372 were unique and addressed in the associated EIS. A general summary of unique comments received during the public comment period on the Draft IRP can be seen in Figure 3-6.

Method of Comment	Number Received
Email	38
Online comment form	104
Webinar comment/question from IRP meetings	16
Oral comment/question from IRP meetings	30
Letters	16
Form Letters (pre-printed post cards)	297
Total	501

Figure 3-6 – Type of Responses Submitted

The following organizations and agencies submitted comments:

- Environmental Protection Agency
- Natural Resource Defense Council
- Southern Alliance for Clean Energy
- Sierra Club
- Earth Justice
- Distributors of TVA power
- State agencies
- Tennessee Valley Public Power Association
- Industry groups (i.e., solar energy, natural gas, etc.)

3.4 Public Input Received During the IRP Process

Public input received during the IRP process covered a wide spectrum of subjects. From public scoping to the comments received on the Draft IRP, the ongoing feedback assisted TVA in identifying the relevant concerns of the public with respect to resource planning. Input received during the IRP process also provided beneficial insight to common public perceptions of TVA programs and willingness to invest in certain resource options. For example, the SRG and public input encouraged TVA to consider larger renewable portfolio targets beyond current resource plans, resulting in consideration of portfolios of 2,500 and 3,500 MW.

Moreover, public input helped develop the framework for analysis and addressed a wide range of issues, including the cost of power, recommended resource options, the environmental impacts of different resource options and the integrated resource planning process. The following sections briefly summarize the issues raised with additional detail provided in the associated EIS.

Costs of New Capacity, Financing Requirements and Rate Implications

Concerns about the ability of TVA to design, build and deliver major new capacity on time and within budget were expressed. Questions about the validity of construction cost estimates for new nuclear capacity were raised.

The public also expressed concerns about TVA's ability to fund future resource additions due to the $30 billion limit on TVA's statutory borrowing authority. TVA's financing options to cover the costs of construction for major capital investments are limited to borrowing, increasing rates or other less traditional forms of financing. There were also concerns about potential impacts on short-term rates. However, some believed that higher rates may promote energy efficiency investments.

While a large number of people were opposed to any future price increases, a number of those who completed the scoping questionnaire expressed a willingness to pay $1-$20 more per month for TVA to increase generation from non-greenhouse gas emitting sources.

Recommended Energy Resource Options

The public made recommendations about TVA's future supply- and demand-side resource options. TVA's future resource portfolio should:

- Avoid or minimize rate increases
- Minimize or reduce pollution and other environmental impacts
- Maximize reliability
- Contain a diversity of fuel sources

The following resources options were mentioned:

Nuclear expansion	• Supported nuclear additions if implemented in a cost-effective, responsible way • Concerned with rising costs and nuclear waste issues related to additions to the nuclear portfolio
EEDR initiatives	• Pleased with the contribution of EEDR in the planning strategies retained in the Draft IRP • Comments regarding the target level of EEDR being studied and the potential for larger amounts of EE to displace new nuclear capacity • Uncertainty about cost, lost revenue impacts and program effectiveness; and questioned measurement and verification of benefits
Renewable additions	• Supported increased renewable generation (including wind, solar, locally-sourced biomass and low-impact hydro) as long as costs are competitive • Stated the need for a stronger commitment to developing renewables within the Tennessee Valley region, particularly solar, as opposed to imported wind power • Questioned system operational impacts caused by intermittent or off-peak resources (i.e., wind and solar)
Idling coal-fired capacity	• Commended TVA on the strategy for coal-fired capacity idling and to consider larger quantities of idled capacity • Concerned with the economic and environmental implications of idling certain coal-fired units • Concerned about TVA's risk exposure for pending carbon legislation and issues related to lead-time for positioning coal-fired assets for idling, retirement and/or return to service
Energy storage	• Recommended an increase in energy storage capability
Natural gas	• Supported additional natural gas-fired generation

Environmental Impacts of Power System Operations

A general concern about pollution was a frequently mentioned issue in regards to the TVA power system. Additionally, much of the public felt the issues with air pollutants, greenhouse gas emissions, climate change, spent nuclear fuel and coal combustion by-products were of high importance.

Many comments encouraged TVA to decrease its emissions of greenhouse gases while others questioned the human influence on climate change. The issue was also raised of the impacts of buying coal from surface mines, particularly mountaintop removal mines, and recommended that TVA stop this practice. The Kingston Fossil Plant ash spill in December 2008 was frequently mentioned.

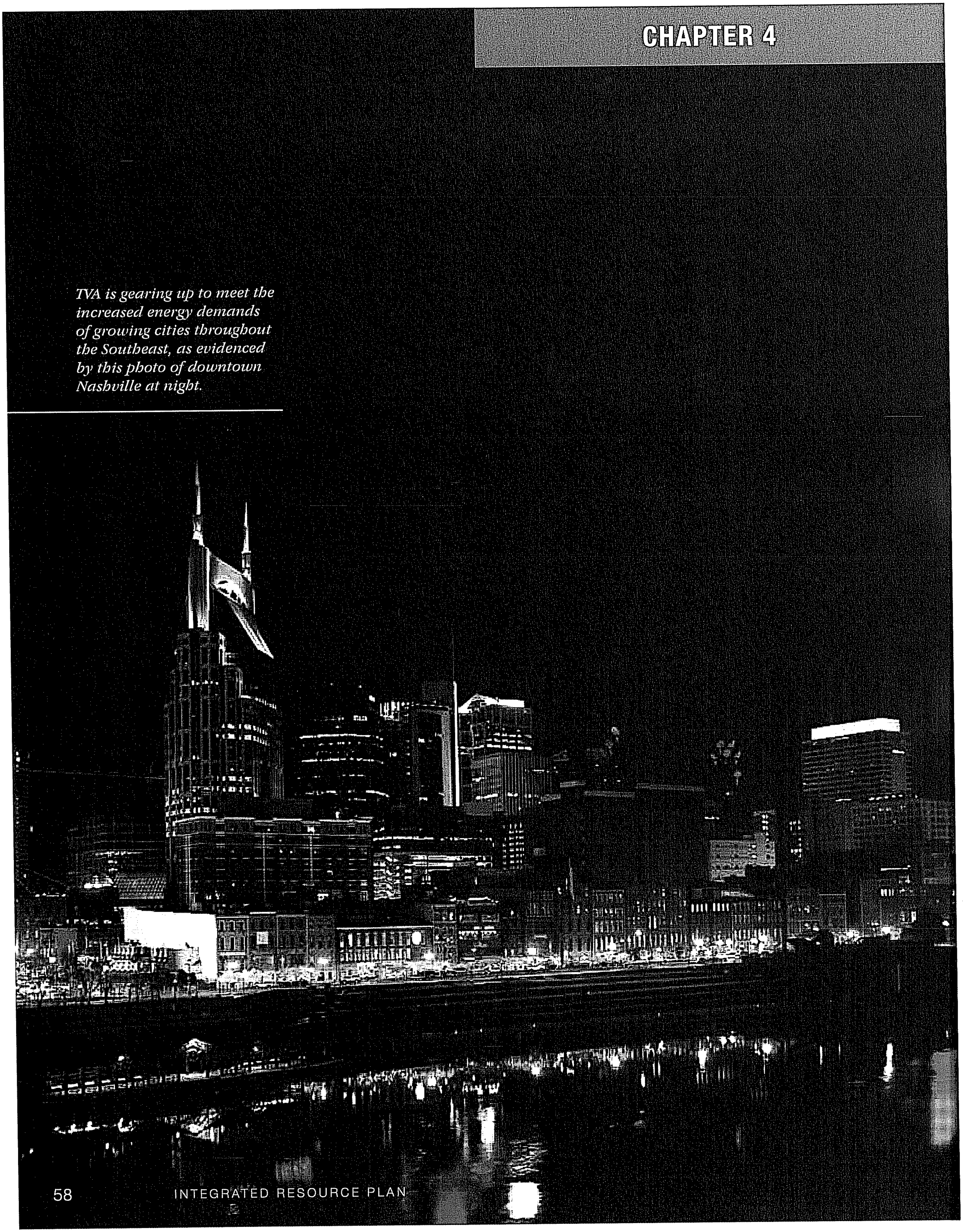
The Integrated Resource Planning Process

Several people addressed the IRP process. Their comments recommended that TVA continue to follow industry standard practices; enter the process without preconceptions about the adequacy of various resource options; be open and transparent throughout the planning process; treat energy efficiency and renewable energy as priority resources and address the total societal costs and benefits.

3.5 Response to Public Input and Comments

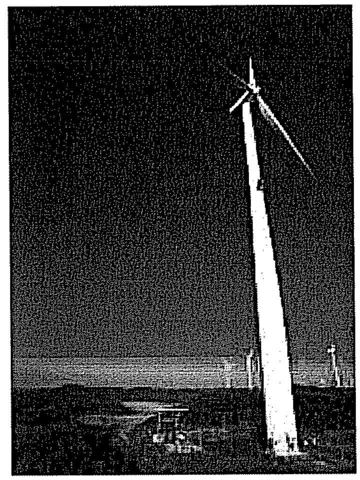
Input received from the general public and stakeholders was a key part of the IRP process. Listening to different stakeholders' perspectives, viewpoints and sometimes competing objectives played a prominent role in choosing a Recommended Planning Direction for TVA. Appendix F – Stakeholder Input Considered and Incorporated provides examples on how key themes were incorporated into the IRP analysis.

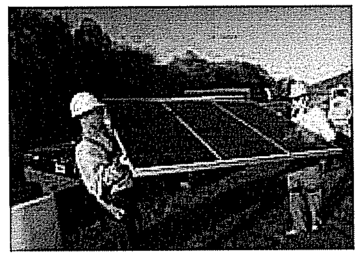
CHAPTER 4

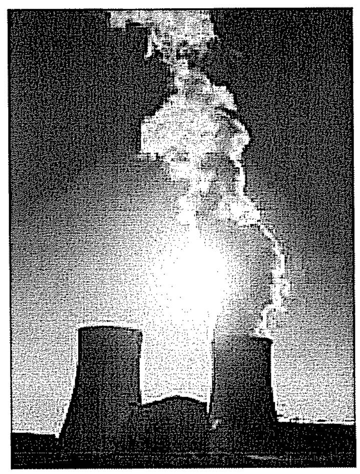


TVA is gearing up to meet the increased energy demands of growing cities throughout the Southeast, as evidenced by this photo of downtown Nashville at night.

Need for Power Analysis





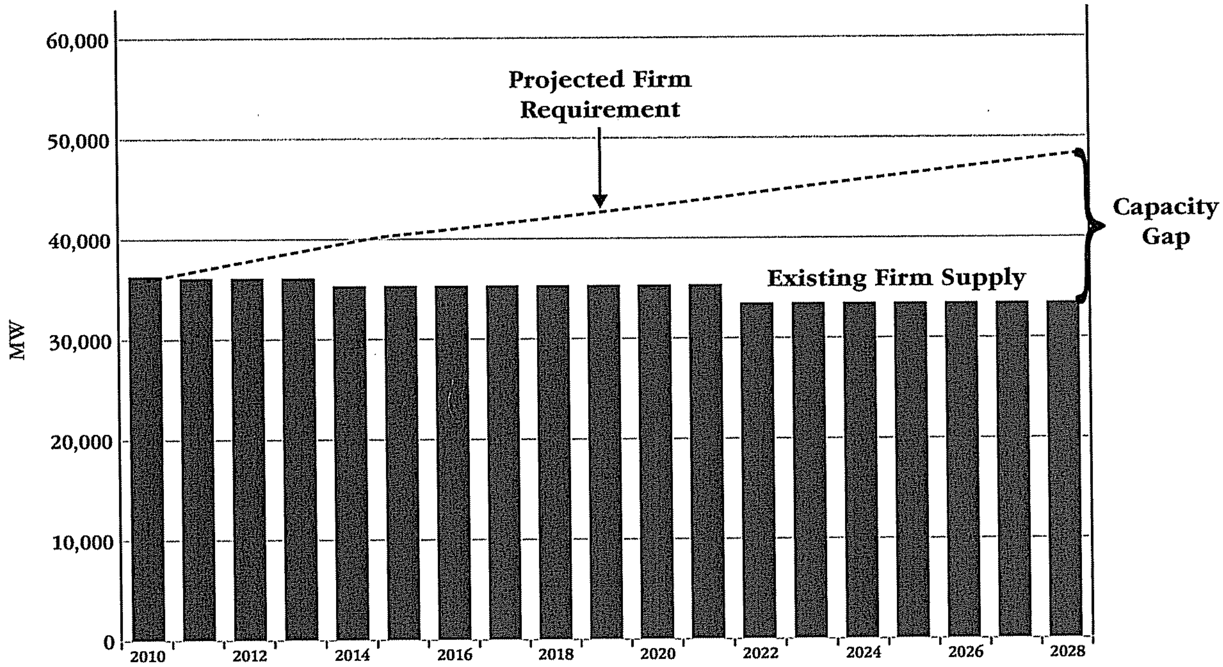


Increasing TVA's production from cleaner energy sources like wind, solar and nuclear are at the core of the overall strategy for the future.

Estimating the Capacity Gap

Projected Firm Requirements are TVA's forecasted electricity requirements to meet demand over time.

Capacity Gap is the difference between total supply and total demand for electricity.



Existing Firm Supply is TVA's existing energy resources to meet projected electricity demand.

4 Need for Power Analysis

The need for power analysis determines the ability of TVA's existing energy resources to meet projected electricity demand. It defines the capacity gap which is the difference between supply and demand over the IRP study period. These needs will continue to vary from season to season, day to day and even minute to minute. For the purposes of this IRP, the need for power was analyzed through 2029.

The execution of this analysis included the following four steps:

1. Estimate demand
2. Determine reserve capacity needs
3. Estimate supply
4. Estimate capacity gap

Demand
+ Reserve Capacity
– Supply

Capacity Gap

4.1 Estimate Demand

Determination of a need for power begins with long-term forecasts of the growth in demand for electricity, both in terms of electricity sales to the end-user and the peak demands those end-users place on the TVA system. These forecasts were developed from individual, detailed forecasts of residential, commercial and industrial sales, which served as the basis for all resource and financial planning activities. Historical forecast accuracy was monitored to ensure errors in data or methodology were quickly identified and fixed. A range of forecasts (high, expected and low) were also generated to ensure that TVA's plans were not too dependent on the accuracy of a single forecast. The following sections provide more detail on the processes used to develop the forecasted demand.

4.1.1 Load Forecasting Methodology

TVA's load forecasting is a complex process that starts with the best available data and is carried out using both econometric (statistical economic) and end-use models. TVA's econometric models link electricity sales to several key economic factors in the market, such as the price of electricity, the price of competing energy source options and the growth in overall economic activity. Specific values for key variables were used to develop forecasts of sales growth in the residential and commercial sectors, as well as in each industrial sector. Underlying trends within each sector, such as the use of various types of equipment or processes, played a major role in forecasting sales.

To capture these trends, along with expected changes in the stock and efficiency of equipment and appliances, TVA used a variety of end-use forecasting models. For example, in the residential sector, sales were forecasted for space heating, air conditioning, water heating and several other uses after accounting for important factors (i.e., changes in efficiency over time, appliance saturation and replacement rates and growth in the average size of the American home). In the commercial sector, a number of categories, including lighting, cooling, refrigeration and space heating, were examined with a similar attention to changes in important variables such as efficiency and saturation.

Since forecasting is inherently uncertain, TVA supplemented its modeling with industry analyses and studies of specific major issues that may have the potential to impact those forecasts. TVA also produced alternative regional forecasts based on different outcomes for key drivers (i.e., economic growth, population growth and economic behaviors) of some of TVA's largest wholesale customers. Two of these alternative forecasts, referred to as the "high-load" and "low-load" forecasts, defined a range of possible future outcomes with a high level of confidence that the true outcome will fall within this range. This ensured that TVA's resource planning took into account the variability that is the hallmark of year-to-year peak demand and energy sales.

Several key inputs were used as drivers of the long-term forecasts of residential, commercial and industrial demand. The most important of these were economic activity, the price of electricity, customer retention and the price of other sources of energy such as natural gas. These key inputs are described in the following sections.

Economic Activity

Periodically, but at least annually, TVA produces a forecast of regional economic activity for budgeting, long-range planning and economic development purposes. These forecasts are based on national forecasts developed by internationally recognized economic forecasting services.

The economy of the TVA service territory has historically been more dependent on manufacturing than the United States on average. Industries such as pulp and paper, aluminum, steel and chemicals have been drawn to the region because of the wide availability of natural resources, access to a skilled workforce and the supply of reliable and affordable electricity. In recent years, regional growth has outpaced national growth as manufacturing activities have grown at a faster pace than non-manufacturing activities. However, this can also mean that in periods of recession, regional growth will contract faster and more sharply given this relatively higher degree of dependence on manufacturing. As evidenced by the ongoing recovery from the most recent recession, the regional economy tends to recover more quickly and robustly.

Future growth is expected to be lower than historical averages as a result of the impacts of the recent recession and ongoing recovery as well as the trend of declining U.S. manufacturing intensity. As markets for manufacturing industries have become global in reach, production capacity has moved overseas from the TVA region for many of the same industries. The decline in demand associated with these off-shore industries has been offset to some degree by the continued growth of the automobile industry in the Southeast over the last 20 years. The TVA region is expected to retain its comparative advantage in the automotive industry, as exemplified by the new Volkswagen auto plant under construction in Chattanooga, Tenn. However, reduced long-term prospects for the U.S. automotive industry will also have an impact on the regional industry.

Other impacts from the recent recession such as increased financial market regulation and tighter credit conditions may also work toward restraining economic growth. These impacts could continue in the long-term resulting in a slowdown in future economic growth for the TVA region and nation.

Despite the impacts of a slowed economy, population growth in the Tennessee Valley region continues to be strong. Most movement into the region is still primarily driven by economic opportunities in the contracting sectors and other expanding sectors in the region. Part of this growth is to serve the existing population (i.e., retail and other services), but, more importantly, a large part of this growth is related to export services that are sold to areas outside the region. Notable examples are corporate headquarters such as Nissan (automobile manufacturing) in Franklin, Tenn., Hospital Corporation of America (the largest private operator of hospitals in the world) in Nashville, Tenn. and FedEx, AutoZone, International Paper and Service Master in Memphis, Tenn.

In addition, the Tennessee Valley has become an attractive region for the growing ranks of America's retirees looking for a moderate climate and a more affordable region than traditional retirement locations and is increasingly fueled as Baby Boomers exit the workforce. The increase in the retiree population has a multiplier effect in the service sector, increasing the need for employees to meet growing demand.

Customer Retention

In the last 20 years, the electric utility industry has undergone a fundamental change in most parts of the nation. In many states, an environment of regulated monopoly has been replaced with varying degrees of competition.

While TVA has contracts with the 155 distributors of TVA power, it is not immune to competitive pressures. The contracts allow distributors to give TVA notice of contract cancellation, after which they may procure power from other sources. Many of TVA's large directly served customers have the option to shift production from plants in the TVA service area to plants in other utilities' service territories if TVA's rates become non-competitive.

The spring 2010 forecast expected TVA's average price of electricity to remain competitive with the rates of other utilities. As a result, the net impact of competition in the medium forecast is that TVA will retain the majority of its current customer base.

Price of Electricity

Forecasts of the retail price for electricity are based on long-term estimates of TVA's total costs to operate and maintain the power system and are adjusted to include an estimate of the historical markups charged by distributors of TVA power. These costs, known in the industry as revenue requirements, are based on estimates of the key costs of generating and delivering electricity, including fuel, variable operations and maintenance costs, capital investment and interest. High and low electricity price forecasts are also derived using high and low values for these same factors after accounting for any relationships that may exist between variables.

Price of Substitute Fuels

Considering electricity is a source of energy, the service derived from consuming electricity can also be obtained, where applications allow, using other sources of energy. If the price of electricity is not competitive with the price of other fuels that can provide the same energy services as electricity, such as water and space heating, customers may move away from electricity in the long-term and substitute cheaper sources of energy. The potential for this type of substitution will depend on the relative prices of other fuels, the ability of the fuel to provide a comparable service and the physical capability to make the change. For example, while consumers can take action to change out electric water heaters and replace electric heat pumps with natural gas furnaces, the ability to utilize another form of energy to power consumer electronics, lighting and many appliances is far more limited by current technology.

Changes in the price of TVA's electricity compared to the price of natural gas and other fuels will influence consumers' choices of appliances—either electric, gas or other fuels. While other substitutions are possible, natural gas prices serve as the benchmark for determining substitution impacts in the load forecasts.

4.1.2 Forecast Accuracy

Forecast accuracy is generally measured in part by error in the forecasts, whether day ahead, year ahead, or multiple years ahead. Figures 4-1 and 4-2 show annual forecasts from 2000 through 2010 for peak load requirements and net system requirements. Figure 4-1 is a comparison of actual and forecasted summer peak demand in MW. Figure 4-2 is a comparison of actual and forecasted net system requirements in GWh. Note that the "Norm.Actual" line represents the normalized value of the annual energy, meaning abnormal weather impacts have been removed.

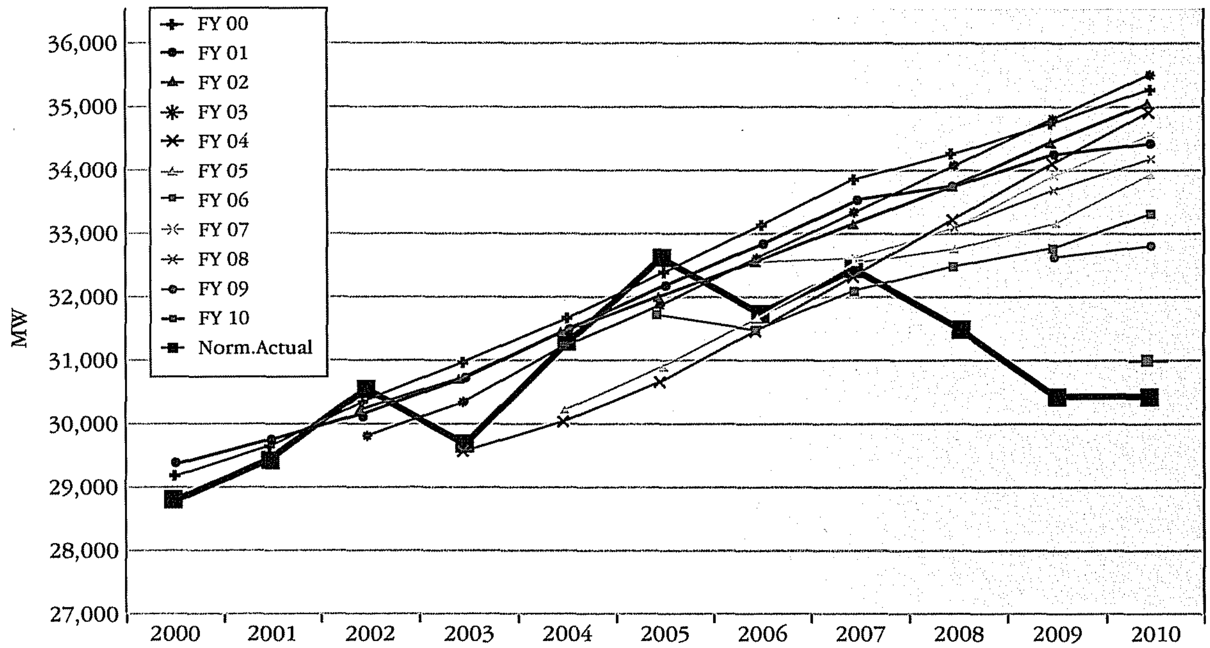


Figure 4-1 – Comparison of Actual and Forecasted Summer Peak Demand (MW)

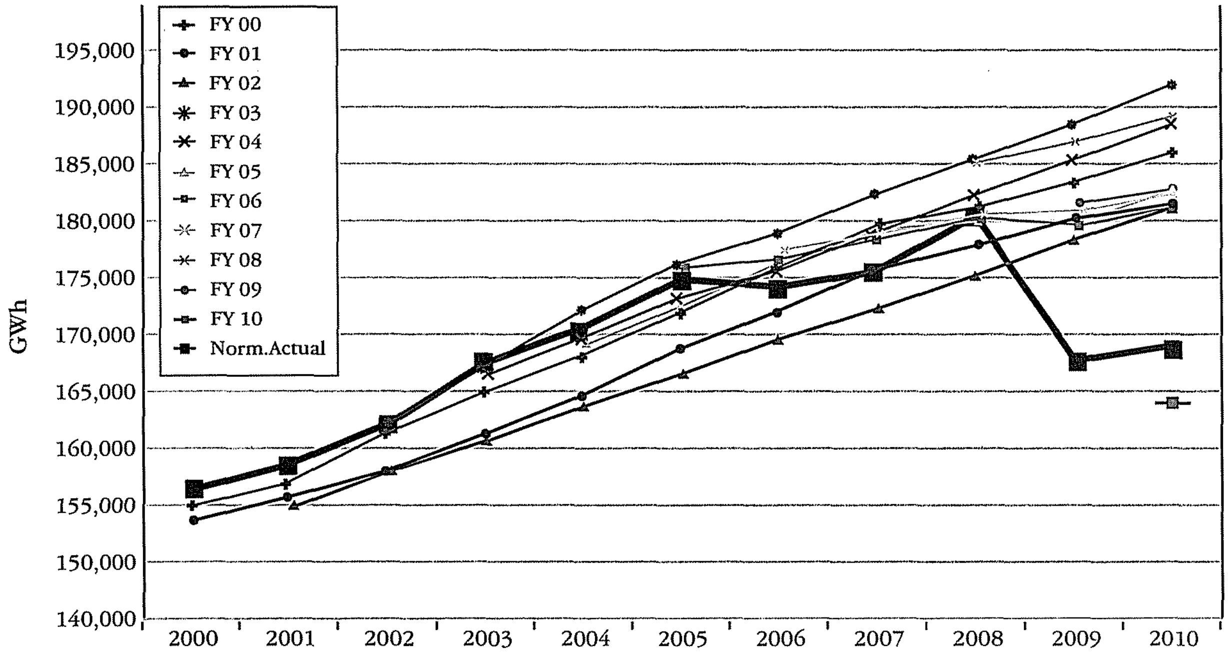


Figure 4-2 – Comparison of Actual and Forecasted Net System Requirements (GWh)

The mean annual percent error (MAPE)[1] of TVA's forecast of net system energy and peak load requirements for the 2000 to 2009 period was 1.9 percent and 2.8 percent, respectively. These include large errors in 2009 as the ramifications of the 2008 financial crisis and resulting economic slowdown impacted the economy. In the TVA service area, the most significant reductions were in the industrial sector, but it has already begun to show signs of recovery. The 2000 to 2008 MAPE was 1.1 percent for net system requirements and 2.2 percent for peak load, which is more representative of the accuracy of TVA year-in and year-out load forecasts. From informal conversations with peer utilities, TVA's MAPE of approximately 1 to 2 percent is in alignment with that of other utilities.

As mentioned previously in Section 4.1.1, while the economy in the Tennessee Valley region may be slightly stimulated by the creation of export services sold to areas outside the TVA region, future growth is expected to be lower than historical averages.

[1]MAPE is the average absolute value of the error each year; it does not allow over-predictions and under-predictions to cancel each other out.

This is a result of a number of factors, which include the impacts of the recent recession and subsequent recovery, the trend of declining U.S. manufacturing and the projected loss of some TVA customer load.

Figures 4-1 and 4-2 show the magnitude of the downturn of TVA net system requirements and summer peak loads due in part to the recession in the region. These trends are the result of a decline in energy usage by TVA customers due to a combination of factors including changes in the regional economy, improved energy efficiency and rising electricity prices.

4.1.3 Forecasts of Peak Load and Energy Requirements

To deal with the inherent uncertainty in forecasting, TVA developed a range of forecasts. Each forecast corresponds to different load scenarios. Scenarios are described in more detail in Chapter 6 – Resource Plan Development and Analysis. Forecasts of net system peak load and energy requirements for the IRP reference case and the highest and lowest scenarios are respectively shown in Figures 4-3 and 4-4. Peak load grew at an average annual rate of 1.3 percent in the Reference Case: Spring 2010, varying from 0 percent in the lowest scenario to 2 percent in the highest scenario. Net system energy requirements grew at an average annual rate of 1 percent in the IRP reference case, varying from 0 percent in the lowest scenario to 1.9 percent in the highest scenario.

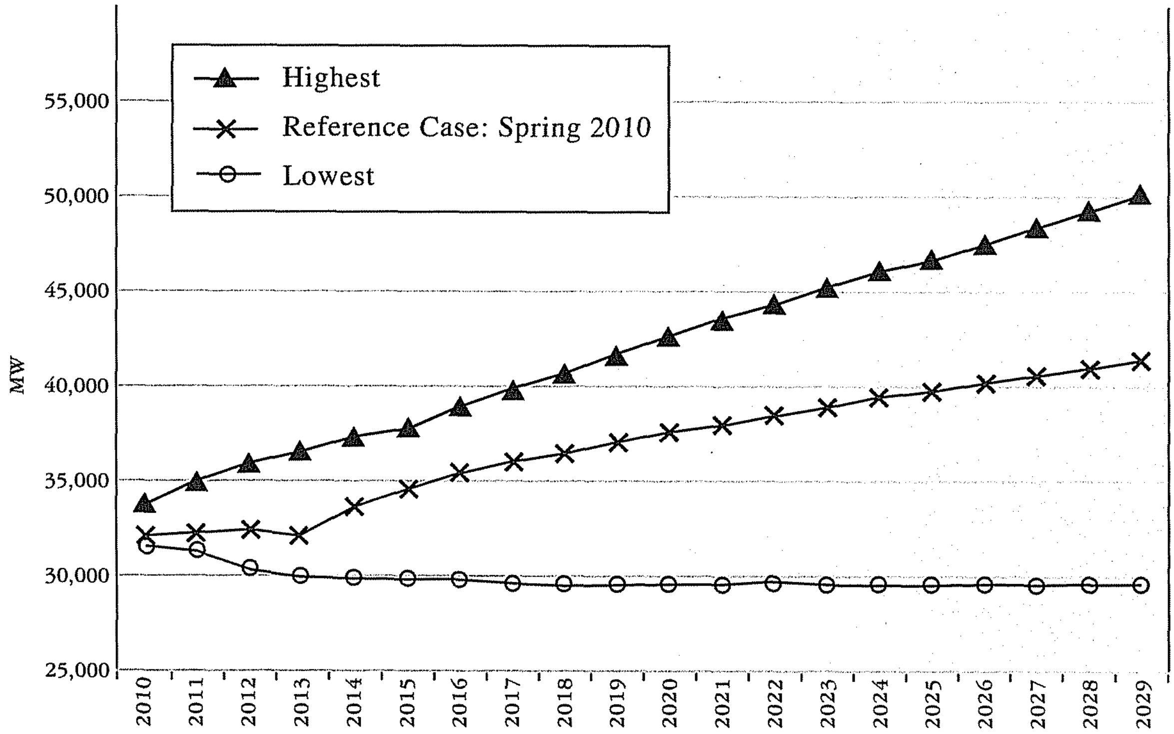


Figure 4-3 – Peak Load Forecast (MW)

The use of ranges ensured that TVA considered a wide spectrum of electricity demand in its service territory and reduced the likelihood that its plans are too dependent on the achievement of single-point estimates of demand growth that make up the midpoints of the forecasts. These ranges are used to inform planning decisions beyond pure least-cost considerations given a specific demand in each year.

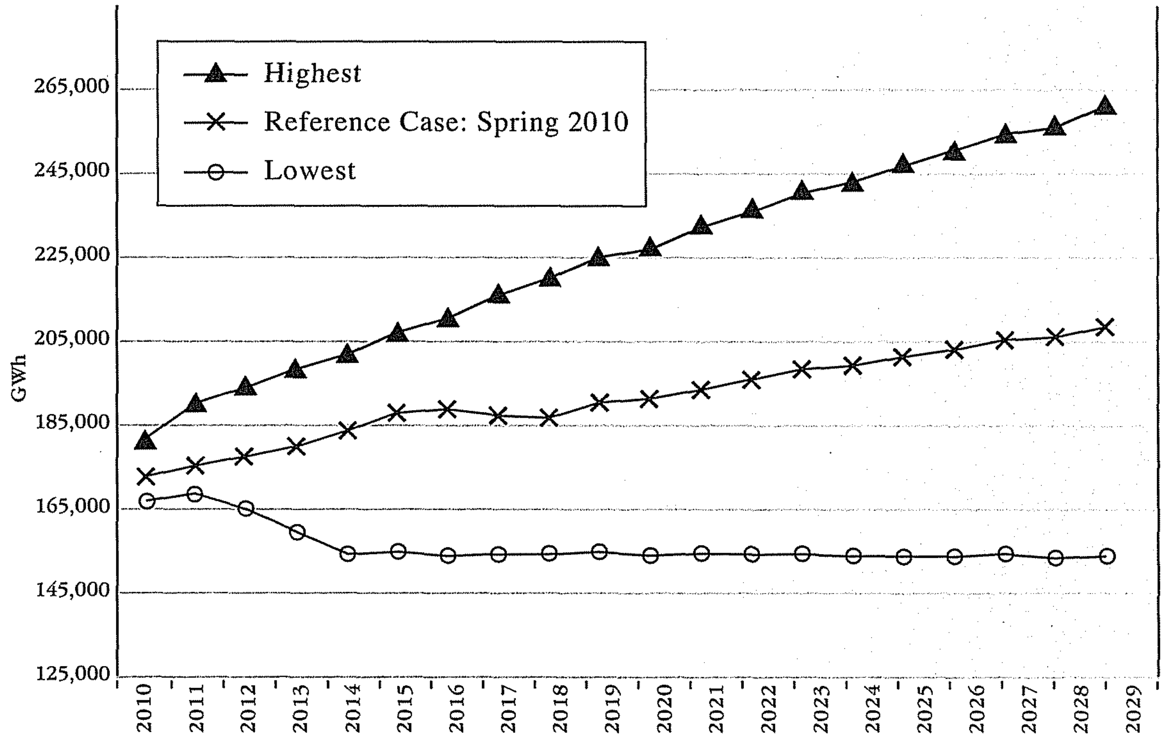


Figure 4-4 – Energy Forecast (GWh)

4.2 Determine Reserve Capacity Needs

To ensure that enough capacity is available to meet peak demand, including contingency for unforeseen events, additional generating capacity beyond which is needed to meet expected peak demand is maintained. This additional generating capacity (reserve capacity) must be large enough to cover the loss of the largest single operating unit (contingency reserves), be able to respond to moment-by-moment changes in system load (regulating reserves) and replace contingency resources should they fail (replacement reserves). Total reserves must also be sufficient to cover uncertainties such as unplanned unit outages, undelivered purchased capacity and load forecasting error.

TVA identified a planning reserve margin based on minimizing overall cost of reliability to the customer. This reserve margin was based on a stochastic analysis that considered the uncertainty of unit availability, transmission capability, economic growth and weather to compute expected reliability costs. From this analysis a target reserve margin was selected such that the cost of additional reserves plus the cost of reliability events to the customer was minimized. This target or optimal reserve margin was adjusted based on TVA's risk tolerance in producing the reserve margin used for planning studies. Based on this methodology, TVA's current planning reserve margin is 15 percent and is applied during both the summer and winter seasons.

4.3 Estimate Supply

Next, the current supply- and demand-side resources available to meet this demand were identified. TVA's generation supply consists of a combination of existing TVA-owned resources, budgeted and approved projects – such as new plant additions and updates to existing assets – and PPAs. Each type of generation can be categorized based on its degree of utilization in serving electricity demand. Generation can also be categorized by capacity, energy type and how it is measured.

4.3.1 Baseload, Intermediate, Peaking and Storage Resources

Figure 4-5 illustrates the uses of baseload, intermediate and peaking resources. Although these categories are useful, the distinction between them is not always clear. For example, a peaking unit, which is typically used to serve only intermittent but short-lived spikes in demand, may from time to time be called on to run continuously for an amount of time even though it may be less economical to do so. This may be due to transmission or other constraints. Similarly, many baseload units are capable of operating at different power levels, which gives them some characteristics of an intermediate or peaking unit. This IRP considered strategies that take advantage of this range of operations.

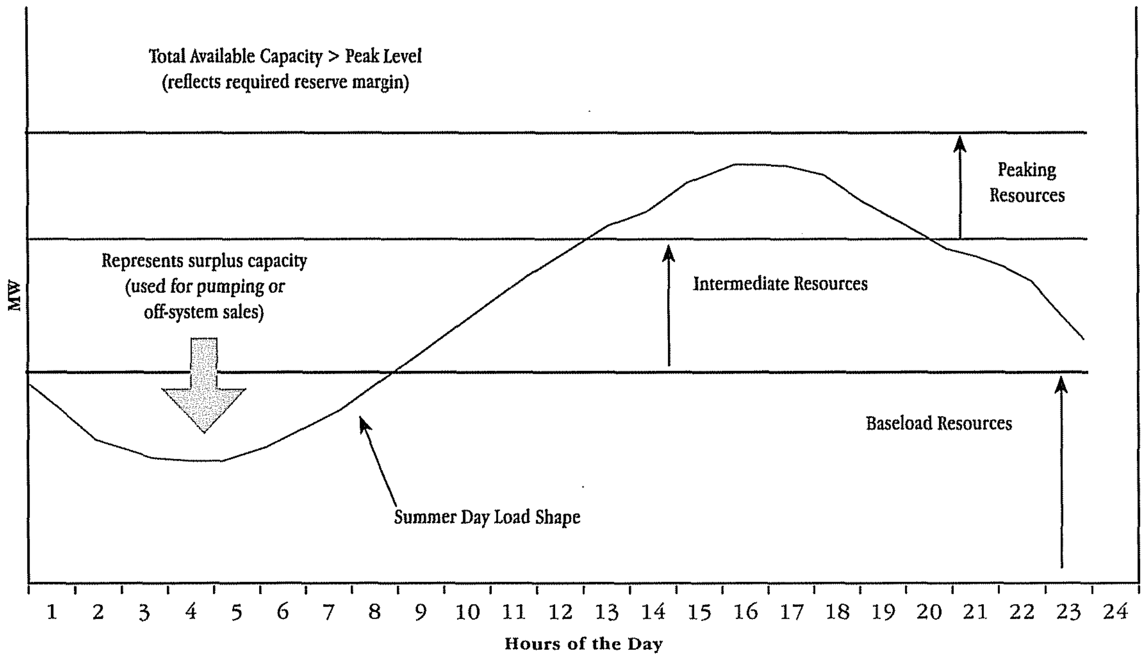


Figure 4-5 – Illustration of Baseload, Intermediate and Peaking Resources (MW)

Baseload Resources

Baseload generators are primarily used to meet energy needs during most hours of the year due to their lower operating costs and high availability. Even though baseload resources typically have higher construction costs than other alternatives, they have much lower fuel and variable costs, especially when fixed costs are expressed on a unit basis. An example of a baseload resource that provides continuous, reliable power over long periods of uniform demand is a nuclear power plant. Some energy providers may also consider natural gas-fired combined cycle plants for use as incremental baseload generators. However, given the historical tendency for natural gas prices to be higher than coal and nuclear fuel prices when expressed on a unit basis, a combined cycle unit may be a more expensive option for larger continuous generation needs. As the fundamentals of fuel supply and demand continue to change and if access to shale gas continues to grow, this relationship may change in the future.

Intermediate Resources

Intermediate resources are primarily used to fill the gap in generation between baseload and peaking needs. These units are required to produce more or less output as the energy demand increases and decreases over time, both during the course of a day and seasonally. Given current fuel prices and relative generating efficiencies, intermediate units are more costly to operate than baseload units, but cheaper than peaking units. This type of generation typically comes from natural gas-fired combined cycle plants and smaller coal-fired plants. Corresponding back-up balancing supply needed for intermittent renewable generation, such as wind or solar, also comes from intermediate resources. It is possible to use the energy generated from a solar or wind project as an intermediate resource with the use of energy storage technologies.

Peaking Resources

Peaking units are expected to operate infrequently during shorter duration, high demand periods. They are essential for maintaining system reliability requirements, as they can ramp up quickly to meet sudden changes in either supply or demand. Typical peaking resources include natural gas-fired combustion turbines (CTs), conventional hydroelectric generation and pumped-storage generation.

Storage Resources

Storage units usually serve the same power supply function as peaking units but use low-cost off-peak electricity to store energy for generation at peak times. An example of a storage unit is a pumped-storage plant that pumps water to a reservoir during periods of low demand and releases it to generate electricity during periods of high demand. Consequently, a storage unit is both a power supply source and an electricity user.

4.3.2 Capacity and Energy

Peaks in a power system are measured in terms of capacity (e.g., MW), which is the instantaneous maximum amount of energy that can be supplied by a generating plant or system. For long-term planning purposes, capacity can be specified in many forms such as nameplate (the maximum design generation), dependable (the maximum that can typically be expected in normal operation), seasonal (the maximum that can be expected during different seasons of the year) and firm (dependable capacity less all known adjustments).

Overall power system usage is measured in terms of energy (e.g., MWh or GWh). Energy is the total amount of power that an asset delivers in a specified time frame.

For example, 1 MW of power delivered for 1 hour equals 1 MWh of energy and 1,000 MWh is equal to 1 GWh. Capacity factor is a measure of the actual energy delivered by a generator compared to the maximum amount it could have produced. Assets that are run constantly, such as nuclear or coal-fired plants, provide a significant amount of energy with capacity factors of more than 90 percent. Assets that are used infrequently, such as combustion turbines, provide relatively little energy with low capacity factors of less than five percent. However, the energy they do produce is crucial because it is often delivered at peak times.

Energy efficiency can also be measured in terms of capacity and energy. Even though energy efficiency does not input power into the system, the effect is similar as it represents power that is not required from another resource. Demand reduction is also measured in capacity and energy, but unlike energy efficiency, it is not a significant reduction in total energy used.

4.3.3 TVA's Generation Mix

TVA's power generation system employs a wide range of technologies to produce electricity and meet the needs of the Tennessee Valley residents, businesses and industries. Figure 4-6 shows a breakdown of firm capacity by technology for TVA's Reference Case: Spring 2010. Figure 4-7 shows a breakdown of energy by technology for TVA's Reference Case: Spring 2010.

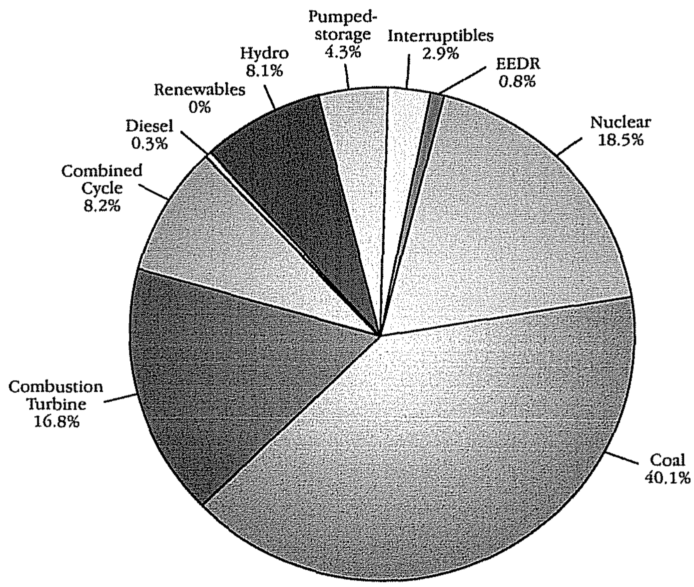


Figure 4-6 – Reference Case: Spring 2010 – Firm Capacity (MW)

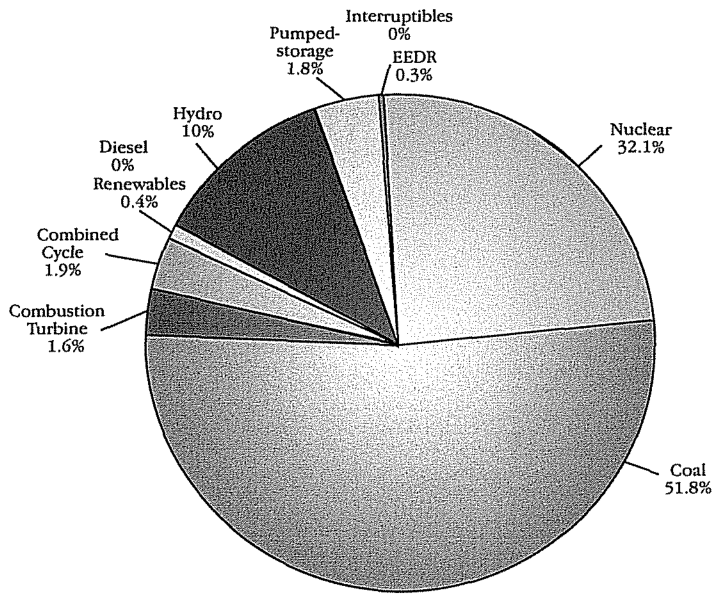


Figure 4-7 – Reference Case: Spring 2010 – Energy (GWh)

In 2010, approximately 56 percent of TVA's electricity was produced from coal-fired and natural gas-fired plants. Nuclear plants produced about 32 percent and hydroelectric plants produced approximately 12 percent. Other generation came from renewable and avoided generation sources such as EEDR.

Figure 4-8 illustrates the changing composition of existing generating resources that are assumed in planning or currently anticipated to be operated through 2029. Figure 4-8 includes only those resources that currently exist or are under contract, such as PPAs and EEDR programs, and changes to existing resources that are planned and approved, such as projects approved by TVA Board of Directors.

The total capacity of existing resources decreases through 2029 primarily because of the potential to idle coal-fired capacity. Total capacity also decreases as PPAs expire and are not extended or replaced. The renewable energy component of the existing portfolio is primarily composed of wind PPAs, which are discussed in the associated EIS. The current EEDR programs are 0.8 percent of the capacity and are also explained in further detail in associated EIS. All IRP strategies included additional renewable resources and EEDR programs beyond those depicted in Figure 4-8, as described in Chapter 7 – Draft Study Results.

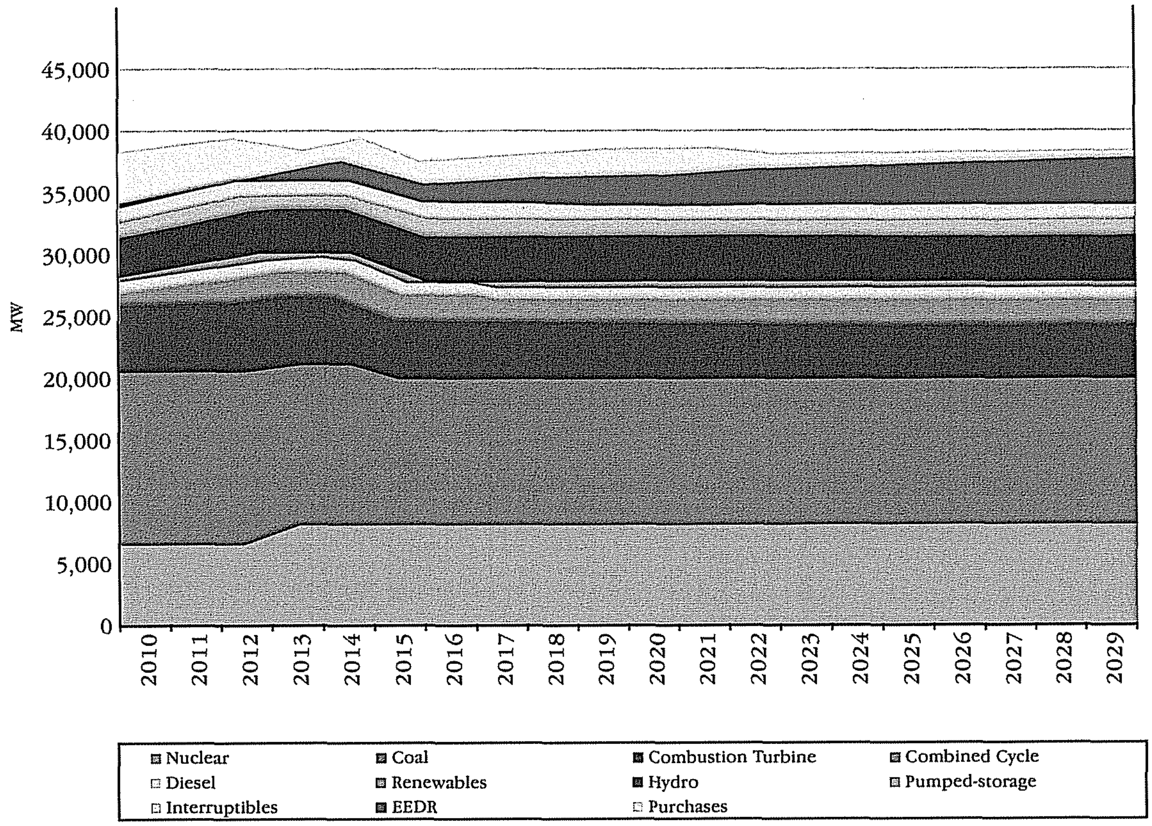


Figure 4-8 – Existing Firm Supply (MW)

The variety of resource types and the different ways they can be used provides TVA with a diverse portfolio of coal, nuclear, hydroelectric, natural gas and oil, market purchases and renewable resources. Used together, they are designed to provide reliable, low-cost power, while minimizing the risk of disproportionate reliance on any one type of resource.

4.4 Estimate the Capacity Gap

The need for power can be expressed by either the capacity or energy gap. Capacity gap is the difference, specified in MW, between the existing firm supply (Figure 4-8) and the expected firm requirements, which are the load forecasts (Figure 4-3) adjusted for any interruptible customer loads plus reserve requirements. In other words, the capacity gap is the difference between total supply and total net demand. This chapter's key reference illustrates the supply, demand and resulting capacity gap.

Energy gap is the amount of energy, specified in GWh, provided by existing resources and the new resources added in the reference case minus the energy required to meet net system requirements. Net system requirement is the required energy needed to serve the load over the entire year. It includes the energy consumed by the end-users plus distribution and transmission losses.

Figure 4-9 shows the resulting capacity gaps based on the spring 2010 peak load forecast as represented in the IRP Reference Case: Spring 2010 scenario, as well as the range corresponding to the highest and lowest capacity gap scenarios.

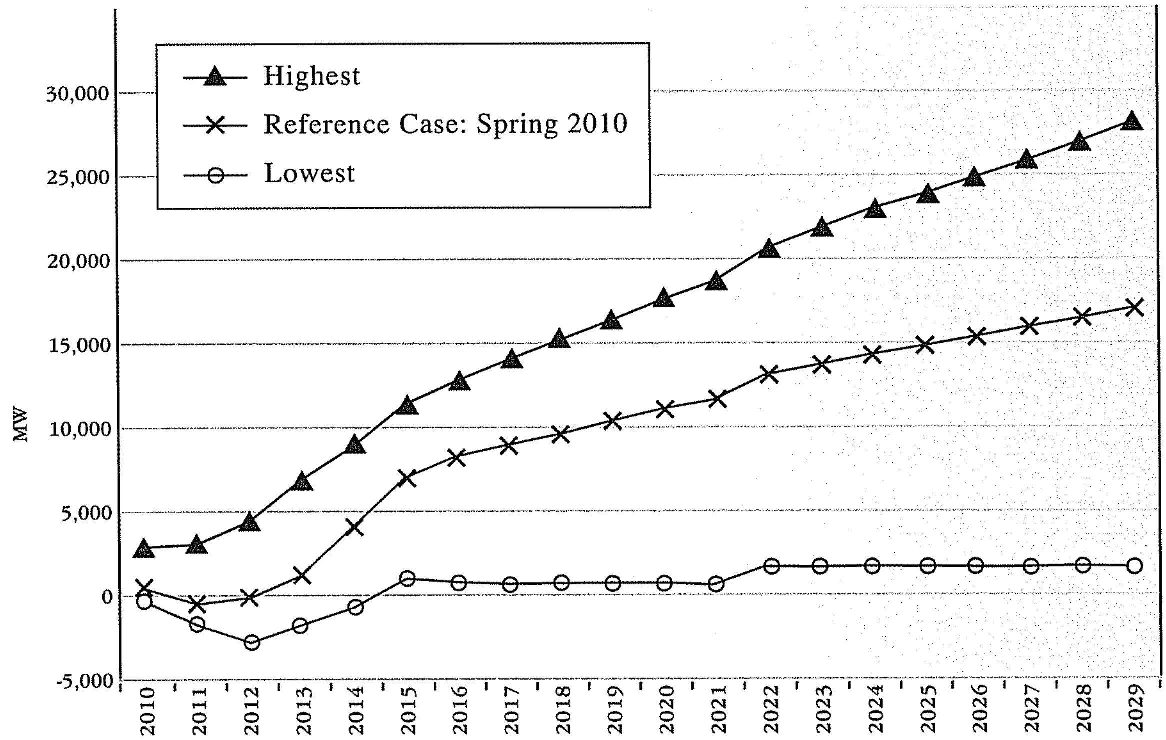


Figure 4-9 – Capacity Gap (MW)

Figure 4-10 shows the same comparison for the energy gaps.

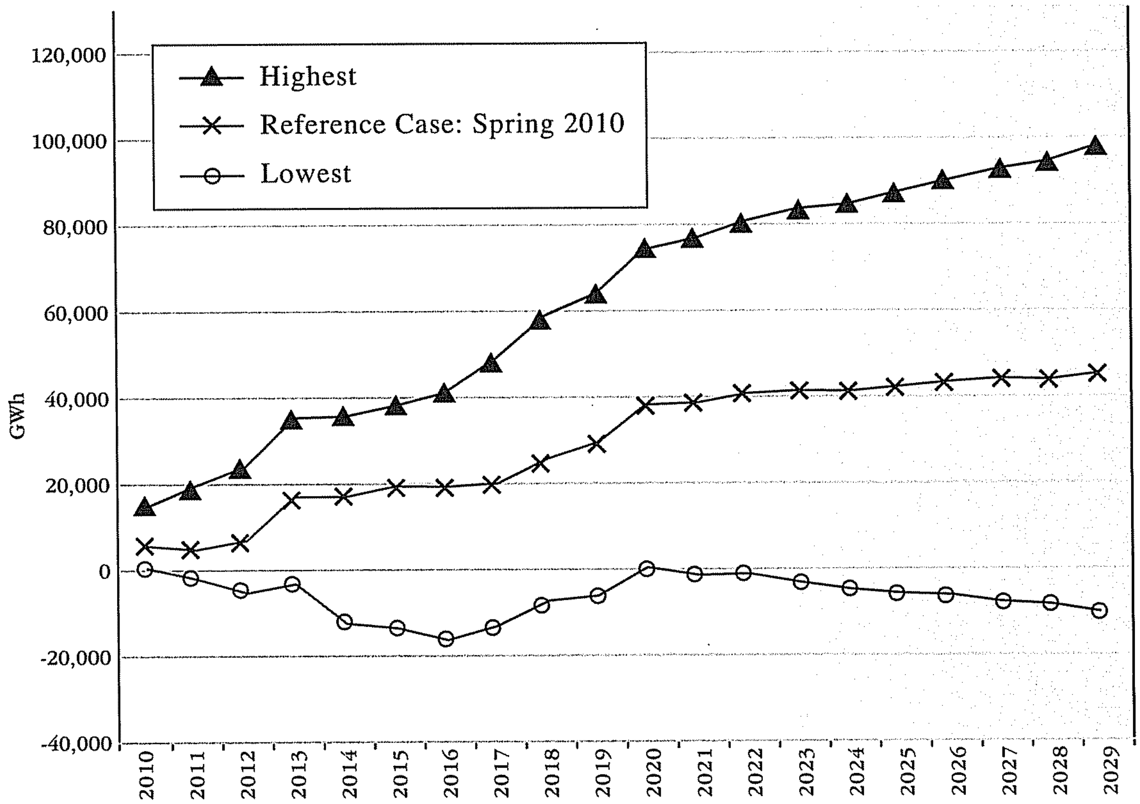
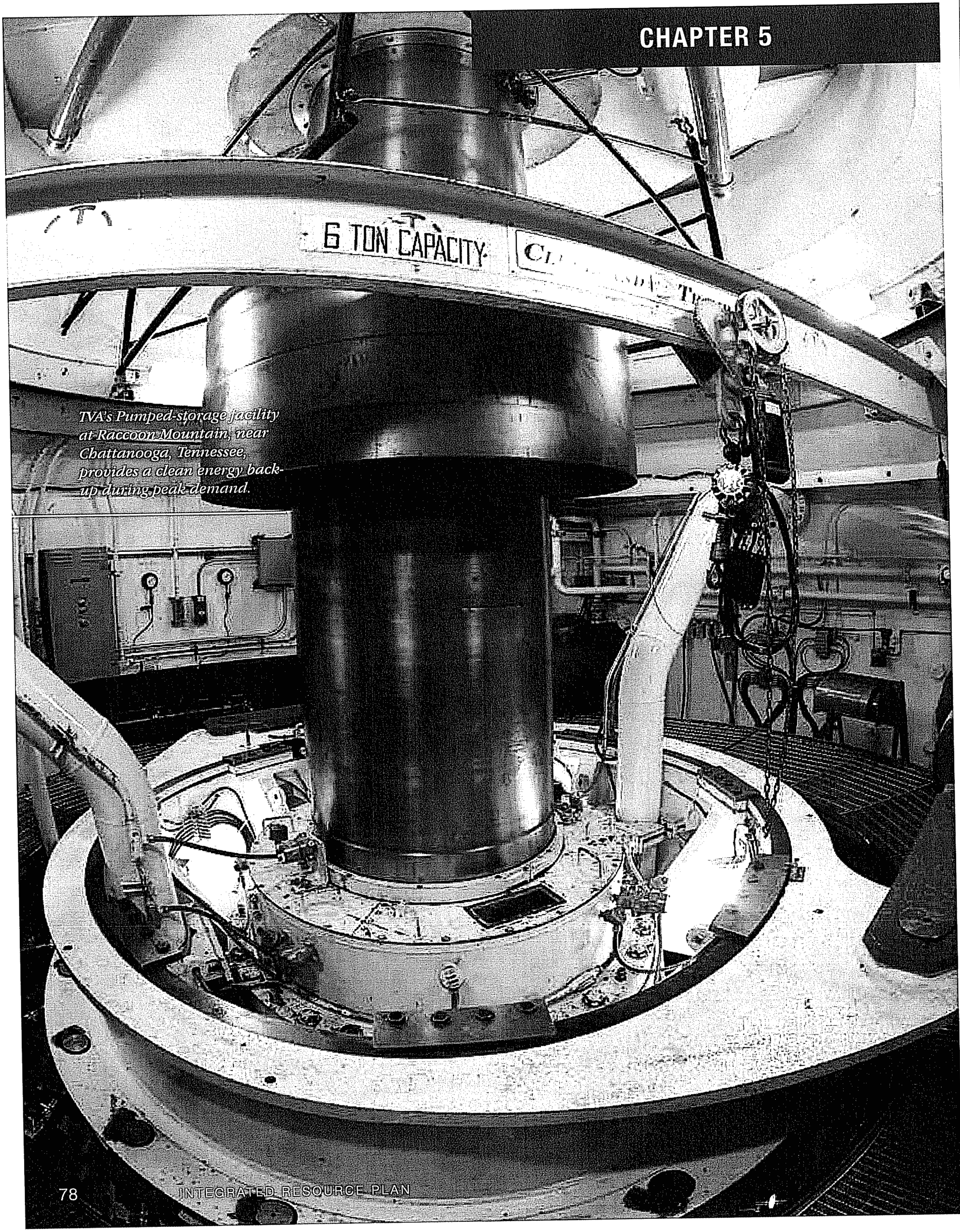


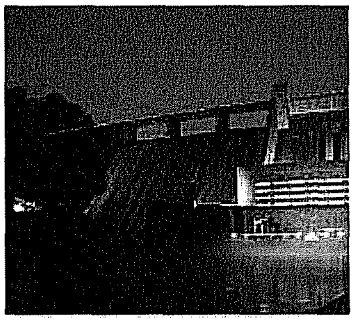
Figure 4-10 – Energy Gap (GWh)

In most scenarios and years, TVA requires additional capacity and energy of 9,600 MW and 29,000 GWh in 2019, increasing to 15,500 MW and 45,000 GWh by 2029. The alternative strategies considered by TVA to meet this gap are detailed in Chapter 7 – Draft Study Results – with the Recommended Planning Direction described in Chapter 8 – Final Study Results and Recommended Planning Direction.



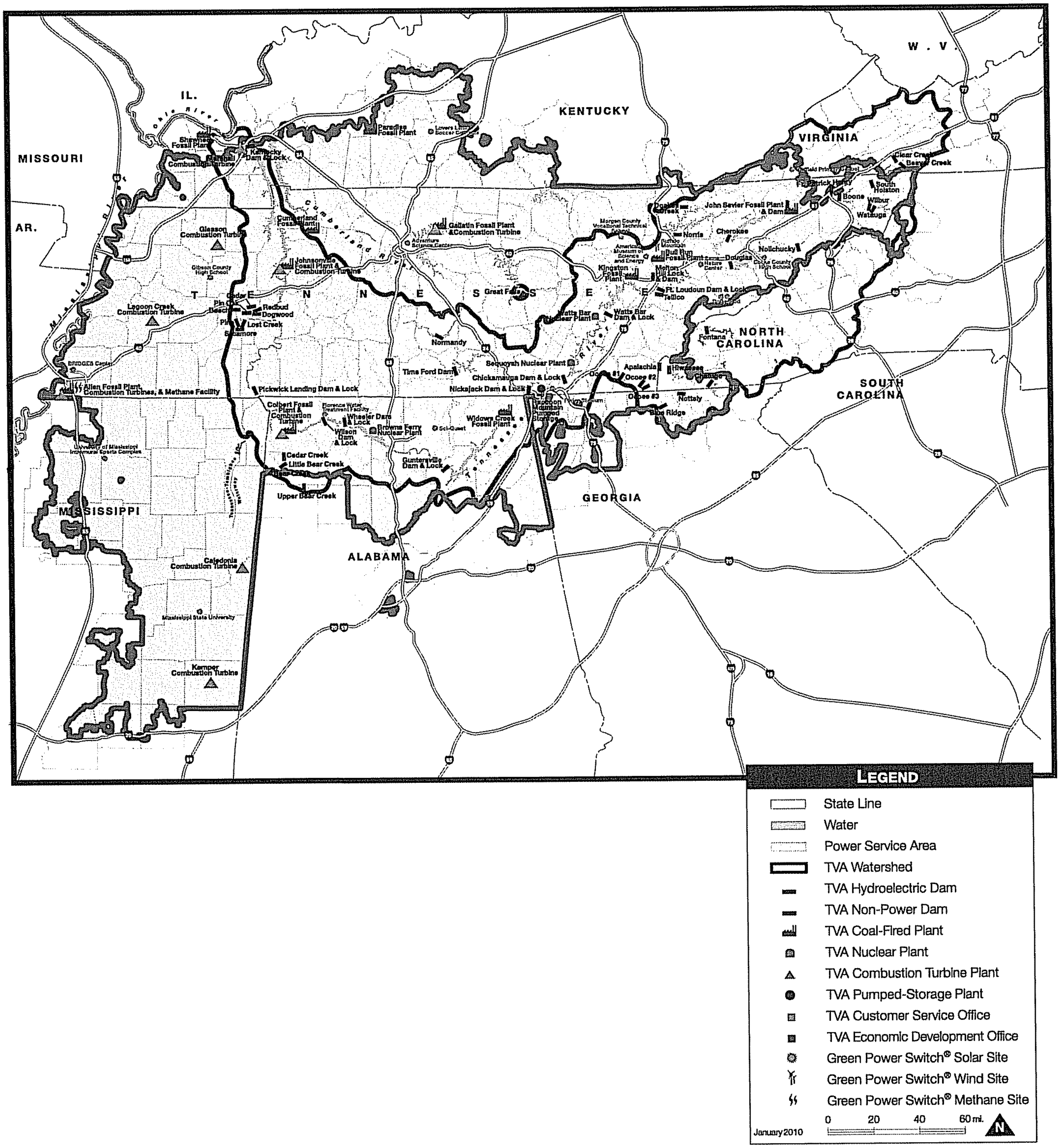
TVA's Pumped-storage facility at Raccoon Mountain, near Chattanooga, Tennessee, provides a clean energy back-up during peak demand.

Energy Resource Options



TVA utilizes a wide variety of assets to meet the energy needs for the people living in the Tennessee Valley.

TVA Regional Assets Map



5 Energy Resource Options

Maintaining the diversity of TVA's energy resource options is fundamental to the ability of providing low-cost, reliable power. In order to fill the forecasted capacity gap defined in Chapter 4 – Need for Power Analysis, TVA considered the addition of a wide range of supply-side generating resources as well as energy efficiency and other demand-side resource options.

TVA's future portfolio of generating assets consists of various fuel sources and diverse technologies that support varying power demand and the other services required for reliable operation of the power system. TVA's resource portfolio also includes power purchases through both short- and long-term contracts, as well as increasing the use of renewable resources and demand-side options (i.e., EEDR programs).

5.1 Selection Criteria

During the scoping process, TVA identified a broad range of resource options. The criteria, listed in Sections 5.1.1 and 5.1.2, were applied to these options to narrow down and establish a more manageable portfolio. A complete list of resource options considered is in the associated EIS.

5.1.1 Criteria for Considering Resource Options

The following criteria were applied to determine what resource options should be considered as viable for the IRP analysis:

- The resource option must utilize a developed and proven technology, or one that has reasonable prospect of becoming commercially available before 2029
- The resource option must be available to TVA, either within the TVA region or importable through market purchases
- The resource option must be economical and contribute to the reduction of air pollutants, including greenhouse gases, from the TVA power supply portfolio in alignment with overall TVA objectives

5.1.2 Criteria for Not Considering Resource Options

The following criteria were applied to determine what resource options should not be considered for further analysis in this IRP:

- The technology is still in very early stages in terms of maturity, in the research phase or under development and not widely available during the IRP planning period
- The resource option was previously considered by TVA and found to be uneconomic or not technically feasible
- The resource option is considered part of what private developers or individuals could elect to do as part of their participation in EEDR programs or their development of renewable resource purchase options for TVA's consideration, but is not a resource option TVA would implement on its own

5.2 Options Included in IRP Evaluation

Resource options that TVA considered in the IRP evaluation included existing assets in TVA's current generation portfolio from TVA-owned facilities and power purchases. Options for new generation also included TVA-owned assets and power purchases as well as repowering of current assets. The primary resource options are nuclear, fossil and renewable generation, energy storage and EEDR. A comprehensive description of all resource options, components, characteristics and technologies is included in the associated EIS.

5.2.1 Nuclear Generation

Nuclear – Existing Generation

The capacity of TVA's existing nuclear units is approximately 6,900 MW, which includes three reactors at Browns Ferry Nuclear Plant, two reactors at Sequoyah Nuclear Plant and one at Watts Bar Nuclear Plant. On Aug. 1, 2007, the TVA Board of Directors approved the completion of the 1,150 MW Unit 2 reactor at the Watts Bar Nuclear Plant. This project is included as a current resource in TVA's generating portfolio and is scheduled for completion in 2013.

Nuclear – New Generation

TVA included Bellefonte Units 1 and 2 at the Bellefonte brownfield site as options in this IRP. In addition to the Bellefonte units, non-site specific options based on the Advanced Passive 1000 reactor design were also considered.

5.2.2 Fossil-Fueled Generation

Coal

Coal – Existing Generation

TVA currently operates 11 coal-fired power plants consisting of 56 active coal-fired generating units and three idled units with a total capacity of 14,500 MW. While some strategies assumed the continued operation of all the remaining coal-fired assets, others assumed placing varying amounts of coal-fired generating capacity into long-term idle status. Three of TVA's coal-fired units were idled in fall 2010. The goal of long-term idling is to preserve the asset, so that with modifications and environmental additions it could be reintroduced into TVA's generating portfolio in the future if power system conditions warrant.

In addition to its owned coal-fired assets, TVA also has access to the output from a coal-fired power plant (of approximately 430 MW) through a long-term PPA.

Coal – New Generation

TVA included supercritical pulverized coal (SCPC) plants with carbon capture and sequestration (CCS) technology as well as integrated gasification combined cycle (IGCC) plants with CCS technology as resource options in the IRP evaluation.

Natural Gas

Natural Gas – Existing Generation

TVA has 87 combustion turbines (CT) at nine power plants, with a combined generating capacity of approximately 6,000 MW. In addition, TVA has the capacity to generate up to 890 MW from its distributor partnership with the Southaven Combined Cycle (CC) Plant and 540 MW at the Lagoon Creek CC Plant, which came online in summer 2010. TVA is also in the process of completing the construction of an 880 MW combined cycle plant at John Sevier that is expected to be operational in 2012.

Power purchases from natural gas-fired units owned by independent power producers are also part of the current resource portfolio. TVA is currently a party to a long-term lease of a 900 MW CC plant and has PPAs of more than 1,000 MW related to natural gas-fired combined cycle plants.

Natural Gas – New Generation

The IRP evaluation includes both combustion turbine and combined cycle natural gas fueled options. Resource options evaluated in this IRP included procurement of power from existing merchant combined cycle plants along with self-built TVA or customer-owned combined cycle plants of up to 1,730 MW without specific site locations. The refurbishment of the natural gas-fired Gleason plant, consisting of three natural gas-fired combustion turbines, was evaluated as a resource option in this IRP, which increases the available capacity from 360 to 530 MW.

Petroleum Fuels

Petroleum Fuels – Existing Generation

Currently, TVA contracts for a number of diesel fuel generated power purchases, totaling 120 MW.

Petroleum Fuels – New Generation

Petroleum power purchases are expected to be phased out by 2029. There are no diesel fuels or other petroleum based resource options as a primary fuel source under consideration in this IRP because of emissions from these facilities.

5.2.3 Renewable Generation

TVA defines renewable energy as energy production that is sustainable and often naturally replenished (e.g., solar, wind, methane, biomass, geothermal and hydro). TVA presently provides renewable energy from TVA facilities and from energy acquired by PPAs. For purposes of the IRP analysis, planning strategies were developed to test a broad range of renewable additions. Therefore, renewable additions incorporated into this IRP were scheduled based on two given renewable portfolio amounts–2,500 MW and 3,500 MW. These targets are beyond TVA's current renewable resource plan (represented as the 1,500 MW portfolio), but would be in addition to TVA's existing clean energy generation sources, which include existing hydro and nuclear. As described below, renewable energy from these resources is also considered in this IRP. Additional detail can be found in Appendix D – Development of Renewable Energy Portfolios.

Conventional Hydroelectric

Hydroelectric – Existing Generation

TVA operates 109 conventional hydroelectric generating facilities at 29 of its dams. These facilities have the capacity to generate 3,538 MW of electricity. TVA is also systematically updating aging turbines and other equipment in its hydro plants.

Hydroelectric – New Generation

TVA included additional as-yet-unapproved modernization projects (a total of 90 MW by 2029) as a resource option for its IRP evaluation as well as up to 144 MW of small hydro by 2029. TVA also included small- and low-head hydropower as an IRP resource option.

Energy Storage

Energy Storage – Existing Generation

TVA operates one large energy storage facility, the 1,615 MW Raccoon Mountain Pumped-Storage Plant, which provides critical flexibility to the TVA system by storing power at off-peak times for use when demand is high.

Energy Storage – New Generation

An additional pumped-storage resource option of 850 MW was included in all cases going forward. In addition, a compressed air energy storage (CAES) option is evaluated in this IRP. TVA did not evaluate any electric battery storage options because of operational limitations.

Wind

Wind – Existing Facilities

TVA currently purchases the output from the Southeast's largest wind farm, consisting of 15 turbines on Buffalo Mountain near Oak Ridge, Tenn. In addition, TVA owns an additional three turbines at that location.

TVA has also entered into contracts with other third-party developers for the long-term purchase of wind power. Requests for proposals were issued in December 2008 for additional wind power. By the end of 2010, TVA had contracted to receive power from approximately 1,600 MW of wind power. Iberdrola Renewables began supplying 300 MW from the Streator Cayuga Ridge Wind Farm in Livingston County, Ill. Additional wind power agreements exist with Horizon Wind Energy LLC (115 MW which started in fall 2010), CPV Renewable Energy Company (365 MW starting 2012) and Invenergy LLC (600 MW starting in 2012). All contracts are contingent on meeting applicable environmental requirements and obtaining firm transmission paths to TVA.

All wind contracts selected were competitive with forecasted market electricity prices at the time those contracts were evaluated. In December 2008, when TVA issued the request for proposals, no economically feasible in-Valley proposals were received.

Wind – New Generation

TVA cannot take direct advantage of the current investment incentives offered to wind power developers. These incentives help make wind power more economically competitive with other generation resources. As such, the option of constructing its own wind power facilities in the TVA region was not included. Instead, TVA has taken the approach of procuring wind power resources through PPAs and included this as a resource option in this IRP. The procurement of wind resources, whether in or imported to the TVA region, through a request for proposal process ensures lower costs to TVA customers. This approach could change to a self-build option in the future if investment incentives and/or future federal or state renewable mandates change.

Solar

Solar – Existing Generation

TVA owns 14 photovoltaic (PV) installations with a combined capacity of about 280 kW of capacity. TVA also purchases power from PV installations through TVA's Generation Partners^{SM} program.

Solar – New Generation

For reasons similar to new wind generation, TVA cannot take advantage of the current investment incentives offered to solar power developers that help make solar power more economically competitive with other resource options. As a result, TVA has taken the approach of procuring solar power resources through PPAs and included it as a resource option in this IRP. This approach could change to a self-build option in the future if investment incentives and/or federal or state renewable mandates change.

Biomass

Biomass – Existing Generation

TVA generates electricity by co-firing methane from a nearby sewage treatment plant at Allen Fossil Plant and by co-firing wood waste at Colbert Fossil Plant. In addition, TVA currently purchases about 91 MW of biomass-fueled generation. These purchases include 9.6 MW of landfill gas generation, 70 MW of wood waste generation and 11 MW of corn milling residue generation.

Biomass – New Generation

TVA included up to 490 MW of biomass generation and landfill gas generation as resource options to be evaluated in this IRP. Most of this biomass is generated through PPAs, while some of it is not. TVA also included the conversion of existing coal-fired units to biomass-fired units and co-firing biomass with coal at existing coal-fired units as IRP resource options to be evaluated. TVA is currently performing biomass fuel availability surveys in the region, and a comprehensive study is underway to assess the feasibility of converting one or more coal-fired units to biomass fuel.

5.2.4 Energy Efficiency and Demand Response

EEDR – Existing Program

TVA has an existing portfolio of programs focused on EEDR. As currently implemented, TVA's EEDR portfolio focuses on reduction in peak demand and has an avoided peak capacity in excess of 300 MW, as of FY10.

EEDR – New Program

This IRP reflects TVA's increased focus on EEDR. These reductions are in addition to energy savings from laws, policies and independent programs of distributors of TVA power. The IRP reference strategy includes an EEDR program that reduces required energy and capacity needs by approximately 14,000 GWh and 4,700 MW, respectively, by 2029.

A list of proposed EEDR programs for TVA implementation is listed in the associated EIS.

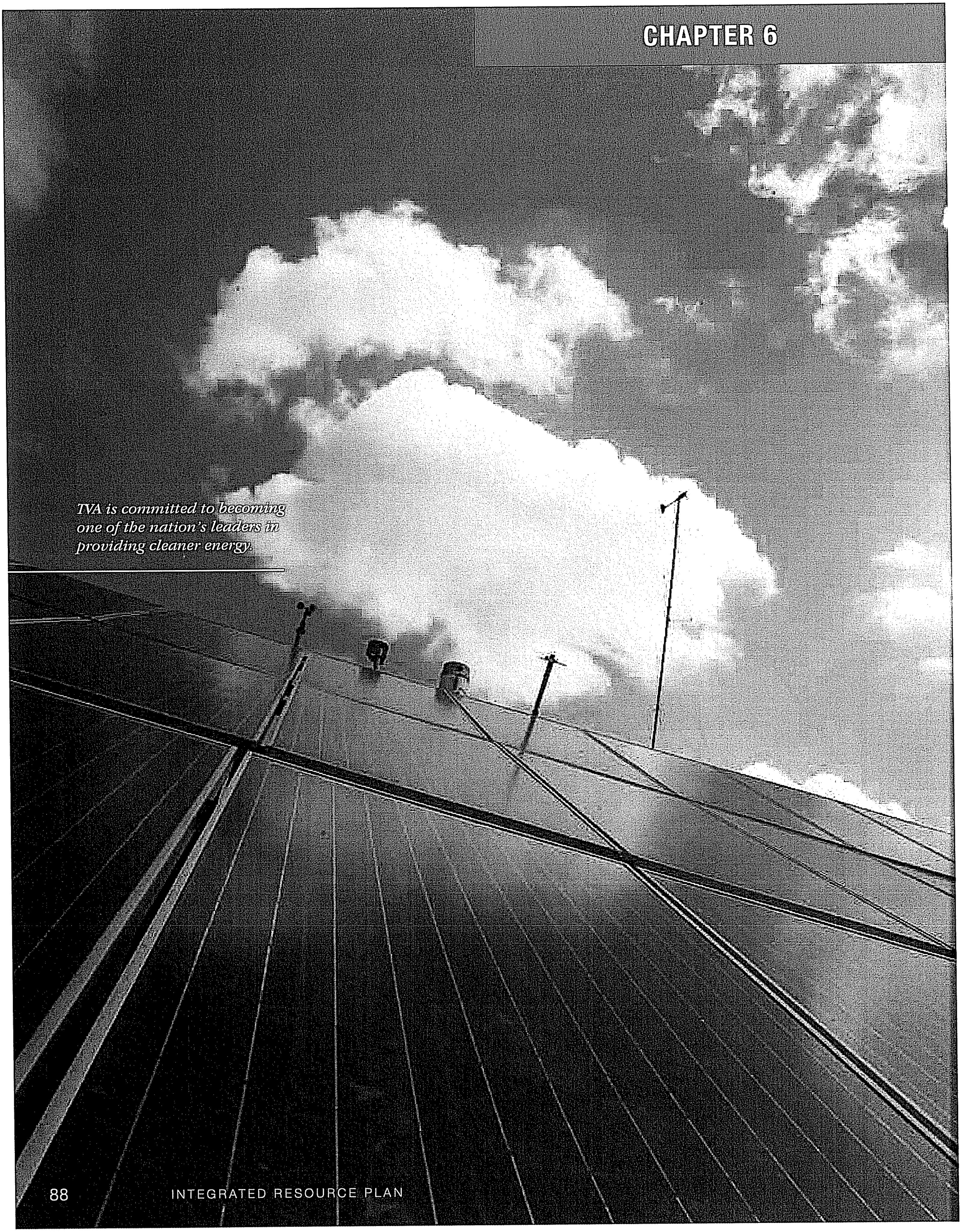
5.2.5 Power Purchases

Power purchases refer to the procurement of energy and/or capacity from other suppliers for use on the TVA system in lieu of TVA constructing and operating its own resources. Power purchases provide additional diversity for TVA's portfolio. TVA is currently a party to numerous short- and long-term PPAs. PPA options are included in the IRP evaluation. For all PPAs, it is assumed that the supplier will either interconnect with TVA transmission or obtain a transmission path to TVA if outside the TVA region.

5.2.6 Repowering Resources

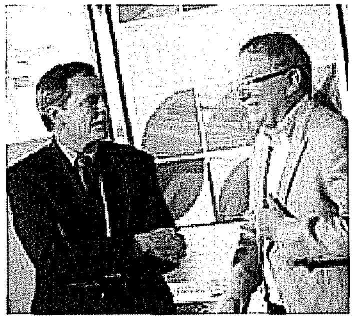
Repowering electrical generating plants is the process by which utilities update and change the fuel source or technology of existing plants to realize gains in efficiency or output that was not possible at the time the plant was constructed. TVA has included approved repowering projects in its forecast for existing resources and included other as-yet-unapproved repowering options in the IRP evaluation.

CHAPTER 6



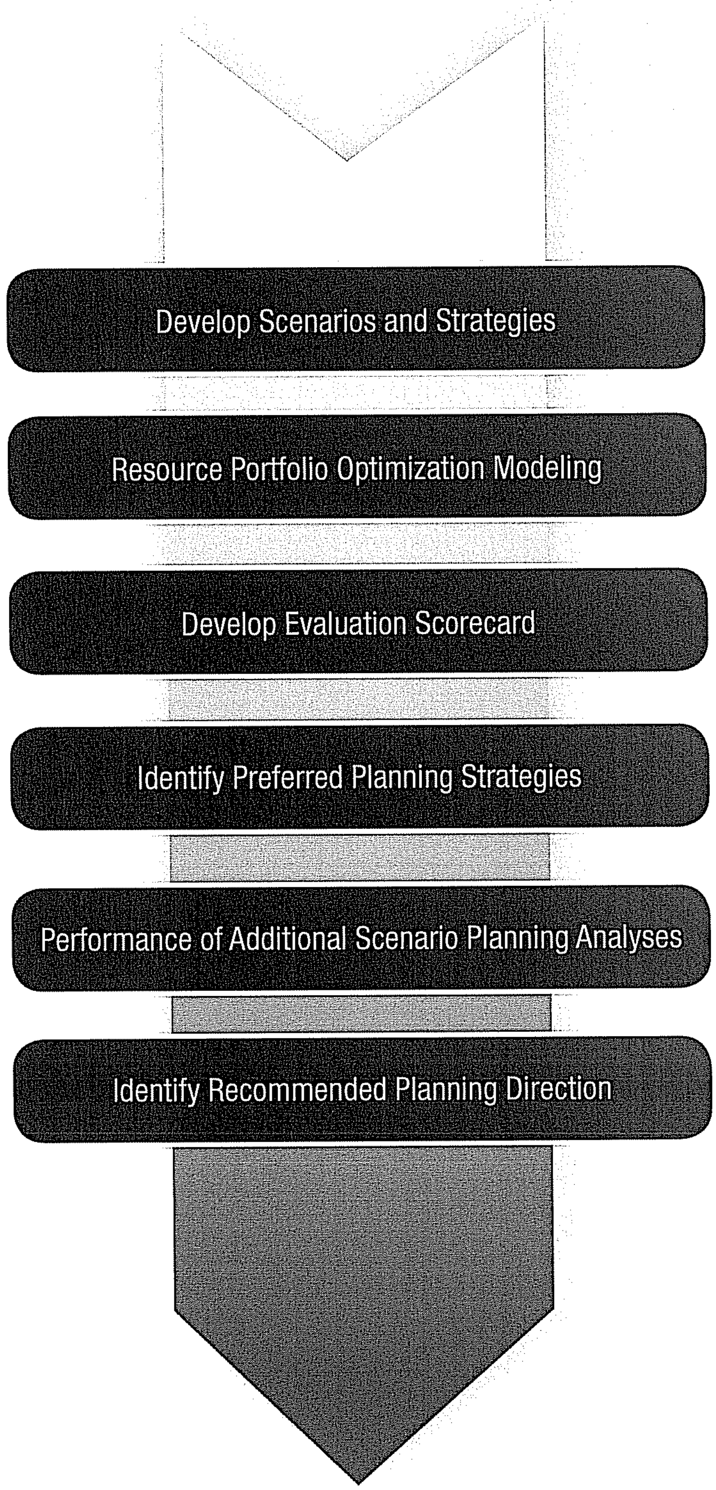
TVA is committed to becoming one of the nation's leaders in providing cleaner energy.

Resource Plan Development and Analysis



TVA's Integrated Resource Plan is a synthesis of public input and strategic planning and professional analysis.

Process for Identifying the Recommended Planning Direction



6 Resource Plan Development and Analysis

TVA employed a scenario planning approach in the development of the Draft and the final IRP. This approach is commonly used in the utility industry. The goal of this approach was to develop a "no-regrets" strategy that was relatively insensitive to uncertainty. In other words, once strategic decisions were made, the strategy would perform well regardless of how the future unfolds. The processes used in the scenario planning approach, including evaluation methods and strategy selection, are outlined in this chapter.

This chapter describes the following six steps of the Draft IRP process:

1. Development of the scenarios and strategies used to conduct the scenario planning analysis
2. Resource portfolios optimization modeling
3. Development of scenario planning scorecards to measure the performance of the portfolios and strategies developed in the scenario planning analysis
4. Identification of preferred planning strategies for publication in the Draft IRP
5. Incorporation of public input and performance of additional scenario planning analyses
6. Identification of the Recommended Planning Direction

6.1 Development of Scenarios and Strategies

Scenario planning is useful for determining how various business decisions will perform in an uncertain future. Multiple strategies, which represented business decisions that TVA can control, were modeled against multiple scenarios, which represented uncertain futures that TVA cannot control. The intersection of a single strategy and a single scenario resulted in a resource portfolio.[1] A portfolio is a 20-year capacity expansion plan that is unique to that strategy and scenario combination.

Modeling multiple strategies within multiple scenarios resulted in a large number of portfolios. Proper analysis of these portfolios was a challenge. Accordingly, during early stages of the analysis, it was more important to observe trends or common characteristics that strategies exhibited over multiple scenarios rather than focusing on specific outcomes in individual portfolios. If a strategy behaved in a similar manner in most scenarios, the modelers could be confident of its robustness. Characteristics of robustness included increased flexibility, less risk over the long term and the ability to mitigate the impacts of

[1]Portfolios are also referred to as capacity expansion plans or resource portfolios

uncertainty. Conversely, a strategy that behaved differently or poorly in each scenario that it was modeled within was considered more risky and indicated a higher probability for disappointment and future regret.

6.1.1 Development of Scenarios

Most quantitative models focus on what is statistically likely based on history, market data and projected future patterns. The scenarios developed for the planning approach operated differently by utilizing assumptions that the future evolves along paths not suggested by history. They were not assigned a probability that one particular future is more likely to occur than another. Using this approach, scenarios identified and framed plausible futures that were studied in the development of the long-range resource plan.

The following three-step process was used to develop scenarios used in this IRP:

1. Identification of key uncertainties
2. Development of scenarios
3. Determination of scenario uncertainty values

Scenarios represent future conditions that TVA cannot control but must adapt to.

Identification of Key Uncertainties

TVA, with input from the SRG, identified uncertainties that were used as building blocks to develop scenarios for this IRP. The key uncertainties are listed in Figure 6-1.

Key Uncertainty	Description
Greenhouse gas (GHG) requirements	• *Reflects level of emission reductions* (CO_2 *and other GHG*) mandated by federal legislation plus the cost of carbon allowances
Environmental outlook	Changes in regulations addressing: • Air emissions (exclusive of GHG) • Land • Water • Waste
Energy efficiency and RES	• Reflects mandates for minimum generation from renewables and the viability of renewable generation sources • It includes the percentage of the RES standard that can be met with energy efficiency
Total load	• Reflects variance of actual load to what is forecast • Accounts for benefits of EEDR penetration
Capital expansion viability & costs	For nuclear, fossil, other generation and transmission, includes risks associated with: • Licensing • Permitting • Project schedule
Financing	• Financial cost (interest rate) of securing capital
Commodity prices	• *Includes natural gas, coal, oil, uranium and spot price of electricity*
Contract purchase power cost	• Reflects demand cost, availability of power and transmission constraints
Change in load shape	Includes effects of factors such as: • Time-of-use rates • Plug-in Hybrid Electric Vehicles (transportation) • Distributed generation • Economics changing customer base • Energy storage • Energy efficiency • Smart grid / demand response
Construction cost escalation	Includes the following for nuclear, fossil and other generation: • Commodity cost escalation • Labor and equipment cost escalation

Figure 6-1 – Key Uncertainties

Development of Scenarios

Scenarios were constructed by utilizing various combinations of the key uncertainties in Figure 6-1. They were then further refined to ensure that the following characteristics for each scenario:

- Represented a plausible, meaningful future "world" (e.g., uncertainties related to cost, regulation and environment)
- Were unique among the scenarios being considered for study
- Reflected a future that TVA could find itself in during the timeframe studied in this IRP

- Placed sufficient stress on the resource selection process
- Provided a foundation for analyzing the robustness, flexibility and adaptability of each combination of various supply- and demand-side options
- Captured relevant key stakeholder interests

A summary of the scenarios selected for the IRP analysis is shown in Figure 6-2. During the scoping phase in summer 2009, Scenarios 1 through 6 were developed for use in the Draft IRP analysis. Scenario 7 was also developed as a reference case in the Draft IRP. It closely resembled TVA's long-term planning outlook at the time the original scenarios were developed. Another reference case, Scenario 8 was added after the publication of the Draft IRP. It captured the impacts of the recent recession and was used in subsequent analysis.

Scenario	Key Characteristics
1 Economy Recovers Dramatically	• Economy recovers stronger than expected and creates high demand for electricity • Carbon legislation and renewable electricity standards are passed • Demand for commodity and construction resources increases • Electricity prices are moderated by increased gas supply
2 Environmental Focus is a National Priority	• Mitigation of climate change effects and development of a "green economy" is a priority • The cost of CO_2 allowances, gas and electricity increase significantly • Industry focus turns to nuclear, renewables, conservation and gas to meet demand
3 Prolonged Economic Malaise	• Prolonged, stagnant economy results in low to negative load growth and delayed expansion of new generation • Federal climate change legislation is delayed due to concerns of adding further pressure to the economy
4 Game-changing Technology	• Strong economy with high demand for electricity and commodities • High price levels and concerns about the environment incentivize conservation • Game-changing technology results in an abrupt decrease in load served after strong growth
5 Energy Independence	• The U.S. focuses on reducing its dependence on non-North American fuel sources • Supply of natural gas is constrained and prices for gas and electricity rise • Energy efficiency and renewable energy move to the forefront as an objective of achieving energy independence
6 Carbon Regulation Creates Economic Downturn	• Federal climate change legislation is passed and implemented quickly • High prices for gas and CO_2 allowances increase electricity prices significantly • U.S. based energy-intensive industry is non-competitive in global markets and leads to an economic downturn
7 Reference Case: Spring 2010	• Economic growth lower than historical averages • Carbon legislation is passed and implemented by 2013 • Natural gas and electricity prices are moderate
8 Reference Case: Great Recession Impacts Recovery	• Economic outlook includes economic recovery, but growth is at a slightly lower rate than Scenario 7 due to lingering recession impacts • Natural gas prices are lower to reflect recent market trends

Figure 6-2 – Scenarios Key Characteristics

Determination of Scenario Uncertainty Values

Once each of the key uncertainties were defined, specific numerical values for each aspect of the scenarios were developed utilizing the following assumptions:

- Climate change uncertainty will be based upon stringency of requirements and timeline required for compliance and cost of CO_2 allowances
- An aggressive EPA regulatory schedule is expected to create additional compliance requirements (e.g., Hazardous Air Pollutants Maximum Achievable Control Technology [HAPs MACT], revised ambient air standards, etc.)
- Command and control regulations for HAPs MACT will likely drive plant-by-plant compliance
- RES will help accomplish GHG reduction required at the federal level
- The spot price of electricity will be correlated with the price of natural gas and coal
- Demand, primarily driven by economic conditions, will be affected by energy efficiency, demand response and other factors
- Schedule risk will be related to demand as well as the uncertainty of permitting and licensing generation and transmission projects
- Economic conditions and associated inflationary pressures will become the primary drivers for changes in financing costs
- Construction costs will be driven by demand as well as availability of labor, equipment, design and raw materials
- Economic conditions will become the primary driver, but the legislative/regulatory environment will apply additional pressure by introducing uncertainty related to potential schedule impacts
- Cost and availability of contract power purchases will be primarily driven by economic conditions and local area demand (i.e., load growth)

A detailed description of each scenario's uncertainty values is shown in Figure 6-3.

Uncertainty	Scenario 1 Economy Recovers Dramatically	Scenario 2 Environmental Focus is a National Priority	Scenario 3 Prolonged Economic Malaise	Scenario 4 Game-changing Technology	Scenario 5 Energy Independence	Scenario 6 Carbon Legislation Creates Economic Downturn	Scenario 7 Reference Case: Spring 2010	Scenario 8 Reference Case: Great Recession Impacts Recovery
GHG requirements	CO_2 price $27/ton ($30/metric ton) in 2014 and $82 ($90/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price $17/ton ($19/metric ton) in 2012 and $94 ($104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	No federal requirement (CO_2 price = $0/ton)	CO_2 price $18/ton ($20/metric ton) in 2013 and $45 ($50/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price $18/ton ($20/metric ton) in 2013 and $45 ($50/metric ton) by 2030. 77% allowance allocation, 41% by 2030	CO_2 price $17/ton ($19/metric ton) in 2012 and $94 ($104/metric ton) by 2030. 77% allowance allocation, 28% by 2030	CO_2 price $15/ton ($17/metric ton) in 2013 and $56 ($62/metric ton) by 2030. 77% allowance allocation, 39% by 2030	Same as Scenario 7
Environmental outlook	Same as Scenario 7	SO_2 controls 2017 NO_x controls Dec 2016 Hg MACT 2014 HAP MACT 2015	No additional requirements (CAIR requirements, with no MACT requirements)	Same as Scenario 7	Same as Scenario 7	Same as Scenario 7	SCR all units by 2017 FGD all units by 2018 HAPs MACT by 2015	Same as Scenario 7
Energy efficiency and RES	RES – 3% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	No federal requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 20% by 2021 (adjusted total retail sales) EE can meet up to 40% or requirement	RES – 5% by 2012, 30% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	RES – 3% by 2012, 15% by 2021 (adjusted total retail sales) EE can meet up to 25% or requirement	Same as Scenario 7
Total load	Med grow to High by 2015; High Dist; Alcoa Returns in 2010+; USEC stays forever; Dept Dist same as Scenario 7	Medium case, then 2012 40% rate increase; Low Dist; DS customer reductions (steel/paper plants); USEC stays forever; Dept Dist same as Scenario 7	Low load case; Low Dist; Alcoa not returning, No HSC & Wacker; USEC leaves June 2013; Dept Disc same as Scenario 7	Med-High load growth through 2020, then 20% decrease 2021-2022 including USEC departure, reduced dist sales & extended TOU	Medium case, then 20% rate increase in 2014; unrestricted PHEV included; TOU	Medium load case 2010-2011; 2012 low case then flat w/no growth; USEC leaves 2013; Alcoa not returning, HSC & Wacker not in; TOU	Moderate growth	Moderate to low growth
Capital expansion viability & costs	Moderate schedule risk	High schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk	Low schedule risk	Moderate schedule risk	Moderate schedule risk
Financing	Higher than Scenario 7 – higher inflation due to higher economic growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Same as Scenario 7 – increased productivity due to technology leads to stronger economic wealth and non-inflationary money growth	Higher than Scenario 7 – higher inflation due to looser monetary policy supporting economic growth	Lower than Scenario 7 – lower inflation due to lower economic growth	Based on current borrowing rate	Based on current borrowing rate
Commodity prices	Gas & coal higher than Scenario 7	Gas higher; coal lower than Scenario 7	Gas much lower & coal much higher than Scenario 7	Gas lower & coal slightly higher than Scenario 7	Gas & coal higher than Scenario 7	Gas & coal much lower than Scenario 7	Gas - $6-8/mmBTU Coal - $40/ton	Gas - $5-7/mmBTU Coal - $40/ton
Contract purchase power cost	Much higher cost & lower availability	Higher cost & lower availability	Same as Scenario 7, then much lower cost with high availability	Higher cost & lower availability, then much lower cost with high availability after load decrease	Higher cost & lower availability	Lower cost with high availability	Moderate cost & availability	Moderate cost & availability
Construction cost escalation	Much higher than Scenario 7 – high economic growth causes high demand for new plants and high escalation rate	Somewhat higher than Scenario 7 – due to "construction costs escalating at high rate due to large volume of nuclear, renewables and env controls projects". High regulatory scrutiny adds to project costs	Lower than Scenario 7 – low load growth leads to low escalation	This scenario has two stages of escalation: 1) higher than Scenario 7 due to high load growth early, then 2) lower escalation when game-changing technology hits	Somewhat higher than Scenario 7 – moderately strong economy and load growth leads to somewhat higher than base escalation	Lower than Scenario 7 – negative load growth, very weak economy and high renewables lead to low escalation	Moderate escalation	Moderate escalation

Figure 6-3 – Scenario Descriptions

6.1.2 Development of Planning Strategies

After development of the scenarios, planning strategies were designed to test the various business decisions and portfolio choices that TVA has control over and might consider. Strategies are very different from the scenarios. Whereas, scenarios describe plausible futures and include factors that TVA cannot control, strategies describe business decisions over which TVA has full control. In the end, a well-designed strategy would perform well in many possible scenarios whereas a poorly designed strategy would frequently not perform well.

The following three-step process was used to design the strategies in this IRP:

1. Identification of key components
2. Development of strategies using key components
3. Definition of strategy

Planning strategies represent decisions and choices over which TVA has full control.

Identification of Key Components

To define the planning strategies, nine distinct categories of components were identified. The choice of components was influenced by comments received during the public scoping period and input from the SRG. Comments stated that TVA should challenge its targets for EEDR and renewables beyond the current portfolios. Accordingly, the ranges for both components were significantly expanded. The components for the planning strategies are described in Figure 6-4.

Component	Description	Type
EEDR portfolio	The level of EEDR included in each strategy	Defined Model Input
Renewable additions	The amount of renewable resources added in each strategy	Defined Model Input
Coal-fired capacity idling	A proposed schedule of coal-fired unit idling that will be tested in each strategy	Defined Model Input
Energy storage	Option to include a pumped-storage unit in selected strategies	Defined Model Input
Nuclear	Constraints related to the addition of new nuclear capacity	Constraint
Coal	Limitations on technology and timing for new coal-fired plants	Constraint
Gas-fired supply (self-build)	Limitations on gas-fired unit expansion	Constraint
Market purchases	Level of market reliance allowed in each strategy	Constraint
Transmission	Type and level of transmission infrastructure required to support resource options in each strategy	Constraint

Figure 6-4 – Components of Planning Strategies

As noted in Figure 6-4, there were two types of components, used in the model.

Defined model inputs	These components were scheduled or predetermined. This applied to both the timing and the quantity of specific asset decisions
Constraints in the model optimization	These components constrained the optimization of asset choices such as minimum build times, technology limitations and other strategic constraints including limits on market purchases. The capacity optimization model selected resources that were consistent with these constraints

Development of Strategies Using Key Components

TVA combined these nine components and created five distinct planning strategies for the Draft IRP analysis. Figure 6-5 lists the five distinct planning strategies and their key characteristics.

Planning Strategy	Key Characteristics
A Limited Change in Current Resource Portfolio	• Retain and maintain existing generating fleet (no additions beyond Watts Bar Unit 2) • Rely on the market to meet future resource needs
B Baseline Plan Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Assumes idling of approximately 2,000 MW of coal-fired capacity • Includes EEDR portfolios and wind PPAs
C Diversity Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Increases the contribution from EEDR portfolio and new renewables • Adds a pumped-storage unit • Assumes idling of approximately 3,000 MW of coal-fired capacity
D Nuclear Focused Resource Portfolio	• Allows for nuclear expansion after 2018 and new gas-fired capacity as needed • Includes an increased EEDR portfolio compared to other strategies • Assumes idling of approximately 7,000 MW of coal-fired capacity • Includes new renewables (same as Strategy C) • Includes a pumped-storage unit
E EEDR and Renewables Focused Resource Portfolio	• Assumes greatest reliance on EEDR portfolio of any strategy and includes largest new renewable portfolio • Assumes idling of approximately 5,000 MW of coal-fired capacity • Delays nuclear expansion until 2022

Figure 6-5 – Planning Strategies Key Characteristics

Definition of Strategy

Once each strategy's key characteristics were defined, specific numerical values for each component of each strategy were defined as shown in Figure 6-6.

Components	Strategy A Limited Change in Current Resource Portfolio	Strategy B Baseline Plan Resource Portfolio	Strategy C Diversity Focused Resource Portfolio	Strategy D Nuclear Focused Resource Portfolio	Strategy E EEDR and Renewable Focused Resource Portfolio
EEDR	1,940 MW & 4,725 annual GWh reductions by 2020	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	4,000 MW & 8,900 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020
Renewable additions	1,300 MW & 4,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy A	2,500 MW & 8,600 GWh competitive renewable resources or PPAs by 2020	Same as Strategy C	3,500 MW & 12,000 GWh competitive renewable resources or PPAs by 2020
Idled coal-fired capacity	No fossil fleet reductions	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	7,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017
Energy storage	No new additions	Same as Strategy A	Add on pumped-storage unit	Same as Strategy C	Same as Strategy A
Nuclear	No new additions after WBN2	First unit online no earlier than 2018 Units at least 2 years apart	Same as Strategy B	First unit online no earlier than 2018 Units at least 2 years apart	First unit online no earlier than 2022 Units at least 2 years apart Additions limited to 3 units
Coal	No new additions	New coal units are outfitted with CCS First unit online no earlier than 2025	Same as Strategy B	Same as Strategy B	No new additions
Gas-fired supply (self-build)	No new additions	Meet remaining supply needs with gas-fired units	Same as Strategy B	Same as Strategy B	Same as Strategy B
Market purchases	No limit on market purchases beyond current contracts and extensions	Purchases beyond current contracts and contract extensions limited to 900 MW	Same as Strategy B	Same as Strategy B	Same as Strategy B
Transmission	Potentially higher level of transmission investment to support market purchases Transmission expansion (if needed) may have impact on resource timing and availability	Complete upgrades to support new supply resources	Increase transmission investment to support new supply resources and ensure system reliability Pursue inter-regional projects to transmit renewable energy	Same as Strategy C	Potentially higher level of transmission investment to support renewable purchases Transmission expansion (if needed) may have impact on resource timing and availability

☐ Defined model inputs ■ Optimized model inputs

Figure 6-6 – Strategy Descriptions

Strategy components were utilized in the modeling in several different ways. For example, Strategy A has specific defined constraints, such as including no new coal additions and 1,300 MW of renewable resource additions. Other components specified timing, such as adding nuclear resources no earlier than 2018 and no new coal additions in Strategy B. Reactive constraints were also identified, such as the need to build additional transmission capacity if imports from renewables exceed a certain limit.

6.2 Resource Portfolios Optimization Modeling

The generation of resource portfolios was a two-step process. First, an optimized capacity expansion plan was generated, which was then followed by a financial analysis. This process was repeated for each strategy/ scenario combination and for additional sensitivity runs.

6.2.1 Development of Optimized Capacity Expansion Plan

TVA utilized a capacity optimization model, System Optimizer, which is an industry standard software model developed by Ventyx. This model utilized an optimization technique where an "objective function" (i.e., total resource plan cost) was minimized and subject to a number of constraints by using mixed integer linear programming.

Resources were selected by adding or subtracting assets based on minimizing the present value of revenue requirements (PVRR). PVRR represents the cumulative present value of total revenue requirements for the study period based on an eight percent discount rate. In other words, it is the today's value of all future costs for the study period discounted to reflect the time value of money and other factors, such as investment risk.

In addition, the following constraints were observed:

- Balance of supply and demand
- Energy balance
- Reserve margin
- Generation and transmission operating limits
- Fuel purchase and utilization limits
- Environmental stewardship

System Optimizer uses a simplified dispatch algorithm to compute production costs. The model used a "representative hours" approach in which average generation and load values in each representative period within a week were scaled up appropriately to span all hours of the week and days of the months.

Year-to-year changes in the resource mix were then evaluated and infeasible states were eliminated. The least-cost path (based on lowest PVRR) from all possible states in the study period was retained in the Draft IRP as the optimized capacity expansion plan.

6.2.2 Evaluation of Detailed Financial Analysis

Next, each capacity expansion plan was evaluated using an hourly production costing algorithm, which calculated detailed production costs of each plan, including fuel and other variable operating costs. These detailed cost simulations provided total strategy costs and financial metrics that were used for evaluation of the results.

This analysis was accomplished using another Ventyx product called Strategic Planning (MIDAS). This software tool uses a chronological production costing algorithm with financial planning data used to assess plan cost, system rate impacts and financial risk. It also utilized a variant of Monte Carlo analysis[1], which is a sophisticated analytical technique that varies important drivers in multiple runs, to create a distribution of total costs rather than a single point estimate, which allows for risk analysis. The Monte Carlo analysis in MIDAS utilized 13 key variables.

The following variables were selected by TVA for the analysis:

- Commodity prices – natural gas, coal, CO_2, SO_2 and NO_x allowances
- Financial parameters – interest rates and electricity market prices
- Operating costs – capital as well as operation and maintenance
- Dispatch costs – hydro generation, fossil and nuclear availability
- Load forecast uncertainty

Total PVRR for each resource plan was calculated taking into account additional considerations. These considerations included the cash flows associated with financing. The model generated multiple combinations of the key assumptions for each year of the study period and computed the costs of each combination. Capital costs for supply-side options were amortized for investment recovery using a real economic carrying cost method that accounted for unequal useful lives of generating assets.

[1]Monte Carlo analysis is also referred to as stochastic analysis

Present value calculations are widely used in business and economics to provide a means to compare cash flows at different times on a meaningful basis. It also ensures that assets with higher capital costs and longer service lives are not unduly penalized relative to assets with lower capital costs and relatively shorter economic lives.

The short-term rate metric was also calculated and provided an alternative representation of the revenue requirements for the 2011-2018 timeframe expressed per MWh. This metric was developed to focus on the near-term impacts to system cost in recognition of TVA's current debt cap of $30 billion and the likelihood that the majority of capital expenditures in the short–term[1] may have to be funded primarily from rates.

6.2.3 Development of Portfolio

Portfolios are the output of the modeling process described in Section 6.2 – Resource Portfolios Optimization Modeling, and represent the outcome of choices made for a given view of the future. During the Draft IRP process, an optimized portfolio was developed for each of the five planning strategies within each of the six scenarios and for the Reference Case: Spring 2010. The end result was 35 distinct portfolios. Each portfolio represented a 20-year capacity expansion plan. The portfolios consisted of assets that represented various resource selections and cost characteristics optimized to meet TVA's capacity and energy needs for the IRP study period.

Due to the nature of the analysis, certain elements (i.e., emphasis on EEDR and nuclear energy) of some strategies remained relatively constant across the scenarios. However, other elements (i.e., amount of natural gas-fired capacity and market purchases) were variable and determined by the interplay between each planning strategy and the scenario within which it was analyzed.

6.3 Development of Evaluation Scorecard

The use of a scenario planning approach, combined with multiple strategies to be considered, resulted in a large number of distinct 20-year resource portfolios that required analysis and evaluation. Rather than looking for the best single solution contained within a large number of portfolios, the scenario planning approach looked for trends or characteristics common to multiple portfolios with a focus on outcomes considered to be successful and the strategies that guided those outcomes. Definition of what is considered successful, although difficult, was a key component in the evaluation of the planning strategies. Development of a scorecard to communicate the success or failure of the different portfolios was vital to the success of this evaluation process.

[1]prior to 2018

The following sections describe the creation of the IRP scorecard, including development of the ranking and strategic metrics. Although not part of the scorecard, the development of a technology innovation narrative is also discussed below.

6.3.1 Scorecard Design

Identification of preferred planning strategies in the Draft IRP and development of the Recommended Planning Direction in the final IRP involved a trade-off analysis. The analysis was focused on multiple metrics of cost, risk, environmental impacts and other aspects of TVA's overall mission.

A scorecard was designed for each strategy and was used to facilitate this trade-off analysis. The scorecard template (Figure 6-7) was comprised of two sections – ranking metrics and strategic metrics. A technology innovation narrative was included apart from the scorecard to help identify which strategies would be supported by particular technology innovations.

	Ranking Metrics			Strategic Metrics				
	Financial Impact			Environmental Stewardship			Economic Impact	
Portfolio	Cost	Risk	Ranking Metric Score	Carbon Footprint	Water Impact	Waste Impact	Total Employment	Growth in Personal Income
		Total Score:						

Figure 6-7 – Planning Strategy Scorecard

Ranking Metrics

Ranking metrics were used to quantify the financial impact of each given portfolio. Two metrics, cost and risk, were selected based on their ability to highlight differences between the portfolios. To further highlight differences, the ranking metric score was calculated as a blend of the two metric's scores.

Cost Metric

Production of the financial metrics PVRR and short-term rates was described in Section 6.2.1. The cost metric used in the strategy scorecard combined these two metrics using the following weighted formula:

Cost = 0.65 * PVRR + 0.35 * short-term rates

By considering the expected values for PVRR and short-term rates, TVA was able to better evaluate the cost and rate implications for various portfolios. The inclusion of both short-term rates and total revenue requirements helped to facilitate a trade-off analysis of alternative resource plans. This allowed TVA to explicitly evaluate funding implications, consistent with stakeholder concerns regarding increasing rate pressures.

Risk Metric

The PVRR risk metric was computed using both a risk ratio and a risk/benefit ratio metric for each portfolio, as shown in Figure 6-8.

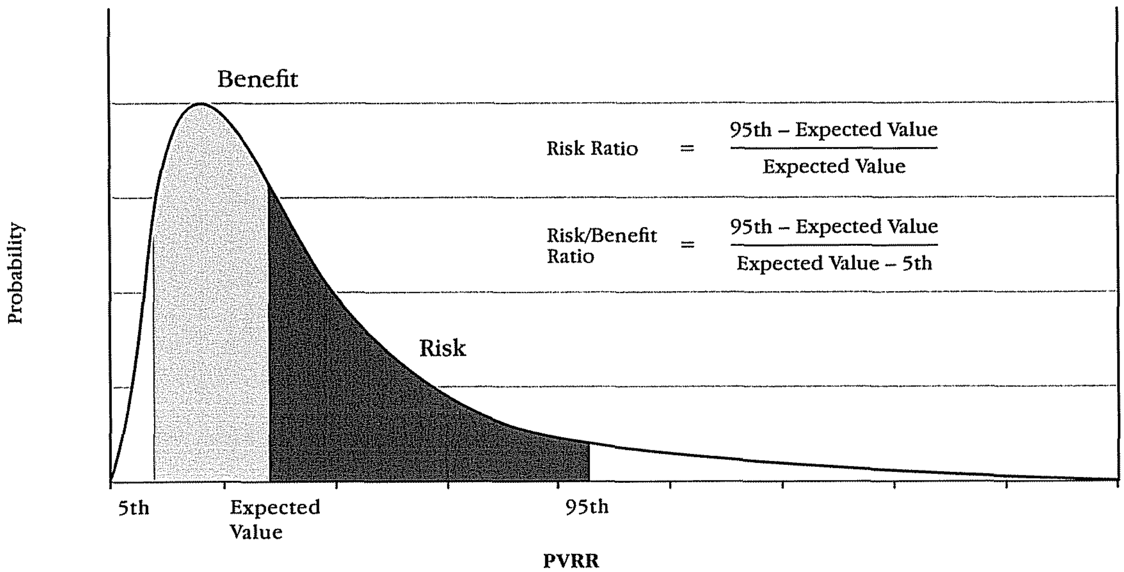


Figure 6-8 – Financial Risk Metrics

The risk metric used in the strategy scorecard combined these two metrics using the following weighted formula.

Risk = 0.65 * risk ratio + 0.35 * risk/benefit ratio

The risk ratio was expressed as the ratio of the difference between the 95th percentile of PVRR from the stochastic analysis and the expected value. It is a measure of the absolute "size" of the risk relative to the expected cost under each strategy within each scenario. A higher value signifies a portfolio with a relatively higher level of risk. The risk/benefit ratio captured the "risk" of a portfolio by examining the potential of exceeding the expected PVRR compared to the benefit of not exceeding the expected PVRR, expressed as a ratio. It compared the potential risks and the potential benefits of a strategy to determine whether or not the "risks and rewards" balance was weighted in favor of the customer.

Ranking Metric Score

The ranking metrics score combined the cost and risk metrics using the following weighted formula.

Ranking metrics score = 0.65 * cost + 0.35 * risk

This metric allowed evaluation of the interaction between financial risks and overall plan cost. For example, desirable low costs may require accepting a greater risk exposure, or to achieve an acceptable level of financial risk may mean selecting a plan with costs that are slightly higher than the least-cost option. The trade-offs required to balance these competing objectives helped identify the preferred planning strategies in the Draft IRP and the Recommended Planning Direction in the final IRP.

Strategic Metrics

Strategic metrics developed to consider other parts of TVA's mission were paired with ranking metrics to complete the IRP scorecard. Two strategic metrics were developed – environmental stewardship and economic impact.

Environmental Stewardship Metric

The environmental stewardship metric was developed to evaluate air, water and waste impacts. In the air metric evaluation, CO_2, SO_2, NO_x and Hg emissions were calculated for each portfolio. Emissions trends for SO_2, NO_x and Hg were steeply reduced because all cases chose large levels of coal-fired unit idling (2,000-7,000 MW) and controlled (90 percent or better emission removal rates) operating units in the future. For simplicity, the air metric was represented as a CO_2 impact footprint factor (annual average tons) because similar trend lines were tracked in all cases for CO_2. No additional significant insight was gained using all air emissions as opposed to using only CO_2. Therefore, the air metric is represented as a CO_2 impact "footprint" factor (annual average tons).

The water component of the environmental stewardship metric represents the thermal load produced through the condenser cooling cycle from steam generating plants to measure thermal impacts to the environment. The water impact was estimated based on the total heat dissipated by the condenser in the generation cooling cycle.

In addition to air and water impacts, certain generation sources produce waste streams that require disposal. The waste component used in this analysis focused on coal and nuclear generation, which are the primary sources of waste streams. The volumetric and disposal costs were used to better normalize differences in mass generated (tons). Waste streams that were estimated included coal ash, flue gas desulfurization/scrubber waste and high- and low-level nuclear waste.

The final evaluation criteria for both water and waste relied on surrogate measures as a proxy for environmental impacts. Both provided a reasonable and balanced method for evaluating planning strategies when compared with other components. Additional detail on the environmental stewardship metrics is in Appendix A – Method for Computing Environmental Impact Metrics.

Economic Impact Metric

Economic impact metrics were included to provide an indication of the impact of each strategy on the general economic conditions in the Tennessee Valley region. The economic metrics were represented by total employment and personal income. These metrics were compared to the impacts of Strategy B – Baseline Plan Resource Portfolio, in Scenario 7.

The IRP study defined economic impact as growth in regional economic activity. Measurement criteria included total personal income in "constant" dollars (i.e., with inflation accounted for) and total employment. These provided measures for the effects of the various planning strategies on the overall, long-term health and welfare of the economy over the next 20 years. This analysis concentrated on changes to the welfare of the general economy due to the strategies. It did not address changes to the distribution of income or employment.

In general, the greater the direct regional expenditures associated with a particular portfolio, the more positive were the effects on the regional economy. This can be offset by the fact that higher rates caused by higher costs have a negative effect on the regional economy. Thus, a resource portfolio that has high expenditures in the Tennessee Valley region may also have high costs and high rates.

The economic impact metrics for a particular planning strategy could be positive or negative depending on the net sum of the expenditure effects and the cost effects. More details about the methodology used to determine the economic impact metrics for the planning strategies is in Appendix B – Method for Computing Economic Metrics.

Scorecard Calculation and Color Coding

The ranking metrics in the scorecard for this IRP were expressed in terms of a 100-point score while ensuring that the relative relationship between the actual values for each portfolio in the strategy was maintained. The following process was used to compute the scores:

- Actual values of ranking metrics (i.e., PVRR, short-term rate impacts) were converted to a relative score on a 100-point scale. This type of scoring helped to assess and prioritize risk and identify the best possible solution
- The highest ranked ("best") value received a 100
- The rest of the scores were based on their relative position to the "best" value (e.g., a value that is 75 percent of the "best" would receive a 75)
- A color-coding method was used to assist in visual comparison of portfolio results. The coding was done within a given scenario. The "best" value for each metric was coded green, the "worst" value was coded red and the values in between were shown with a shaded color that corresponded to the relationship of the score values

An example of the translation from actual values to ranking metric scores is shown in Figure 6-9. The figure shows the conversion for the short-term rate metric.

Raw ranking metric value for short-term rate impacts in Scenario 1 are shown to right

Ranking Metric Scores		
	Strategy	Scenario 1
Average of ST Rates $/MWh (level 2011-18)	A	76.82
	B	78.67
	C	79.95
	D	84.61
	E	80.41

The "best" (in this case lowest) value within a scenario gets a score of 100

Strategy D is 10.13% higher than the "best" value and receives a score of 89.87

Scores are converted from the raw scores as shown and are included in the planning strategy score cards

Converted Ranking Metric Scores		
	Strategy	Scenario 1
Average of ST Rates (level 2011-18)	A	100.00
	B	97.59
	C	95.93
	D	89.87
	E	95.34

All other scores are assigned a value based on their relative position to the "best" score

Figure 6-9 – Ranking Metrics Example

The strategic metrics were included in the scorecard in two ways. First, the environmental stewardship metrics values were translated into a relative scoring system, known as a Harvey Ball rating system. Second, the economic impact metrics were represented by a percent change from a reference case.

For the environmental stewardship metrics, the data was coded in a given scenario so that the relative relationship (rank order) among the strategies was indicated by the amount of the ball that was filled in. Figure 6-10 shows an example of how this translation was done.

- This is an example of how the Harvey Ball ratings were applied to the Carbon Footprint strategic metric
- Expected values for annual CO_2 emissions from stochastic analysis are shown to the right
- Planning strategies were ranked based on their performance within each scenario

  In this example, 1=highest and 5=lowest
- In this example, quantitative data was available to support the ranking, however, other strategic metrics may have required qualitative assessment for ranking
- The appropriate Harvey Ball was assigned based on the rankings

Average Annual CO_2 Emissions (Million Tons)

	Scenario						
Strategy	1	2	3	4	5	6	7
A	2,054	1,719	1,402	1,775	1,723	1,190	1,767
B	1,774	1,461	1,317	1,518	1,480	1,138	1,533
C	1,673	1,418	1,210	1,408	1,422	1,035	1,427
D	1,468	1,170	1,058	1,256	1,204	962	1,249
E	1,613	1,299	1,106	1,410	1,303	959	1,352

Carbon Footprint Rankings Within Scenarios

	Scenario						
Strategy	1	2	3	4	5	6	7
A	5	5	5	5	5	5	5
B	4	4	4	4	4	4	4
C	3	3	3	2	3	3	3
D	1	1	1	1	1	2	1
E	2	2	2	3	2	1	2

Populated Carbon Footprint Strategic Metric

Legend	
●	Better
◕	↑
◑	
◔	
○	

	Scenario						
Strategy	1	2	3	4	5	6	7
A	○	○	○	○	○	○	○
B	◔	◔	◔	◔	◔	◔	◔
C	◑	◑	◑	◕	◑	◑	◑
D	●	●	●	●	●	◕	●
E	◕	◕	◕	◑	◕	●	◕

Figure 6-10 – Example of Draft IRP Scoring Process – Carbon Footprint

For the economic impact metrics, data were included in the scorecard as a percent change from the reference portfolio (Strategy B in Scenario 7). Instead of computing impacts for all 35 portfolios, only the range of possible impacts was evaluated.

The range of possible impacts was evaluated by computing the values for each planning strategy in Scenarios 1 and 6. The changes in employment and personal income in these scenarios relative to the reference portfolio (Strategy B in Scenario 7) indicated the maximum impacts that could result in any of the other scenario/strategy combinations.

6.3.2 Technology Innovations Narrative

In addition to the ranking and strategic metrics, a brief narrative of technology innovations associated with each planning strategy was prepared for the TVA Board of Directors. The narrative gave insight into the technology utilization implicit in each strategy for the Draft IRP.

This narrative was not a metric, but included as a supplement to the fully populated scorecard as background information to consider for selection of a Recommended Planning Direction. The technology innovation narrative discussed which technologies would justify investment to enable the resource mix identified in each strategy (e.g., a planning strategy with extensive EEDR may need smart grid investments for energy savings to be fully realized). A full description of the technology innovation matrix is in Chapter 7 – Draft Study Results.

6.4 Identification of Preferred Planning Strategies in the Draft IRP

Identification of preferred planning strategies was the key deliverable of the Draft IRP. The preferred planning strategies were identified by using the following three steps:

1. Scoring
2. Sensitivity analysis
3. Identification of preferred planning strategies

6.4.1 Scoring

For the Draft IRP, the identification of preferred planning strategies began by computing a score for each of the 35 portfolios evaluated in the study. Scores were based on the expected value for the cost and risk metrics. A total planning score was then calculated by summing the scores (ranking metrics) for each portfolio produced. Strategic metrics were combined with the ranking metrics for each of the selected reference resource portfolios to complete the scorecard. The technology innovation narrative was also utilized to help inform the scorecard. The initial scorecard was publicly shared during the Draft IRP and associated EIS public comment period and helped to facilitate discussion of trade-offs, constraints and compromises by considering the scorecard values of cost, risk and the strategic metrics.

6.4.2 Sensitivity Analyses

Sensitivity analyses were conducted to refine the preliminary results. The results focused on key assumptions in the strategies based on review of the scorecard results. For the

Draft IRP, sensitivity analyses consisted of selected cases intended to assess the robustness of the top performing strategies prior to selecting which strategies would be retained for further analysis for the final IRP.

6.4.3 Identification of Preferred Planning Strategies

By utilizing the ranking metrics, strategic metrics and technology innovation narrative, the preferred planning strategies were identified. Three strategies were retained in the Draft IRP – Strategies C, E and B. Resource portfolios were then identified from the preferred planning strategies. These resource portfolios represented the planning strategies for the purpose of comparative analysis and impact assessment and were used to define the broad range of options considered in the Draft IRP.

6.5 Incorporation of Public Input and Performance of Additional Scenario Planning Analyses

Following publication of the Draft IRP, the data used for analysis was re-evaluated and refreshed for key assumptions like load forecasts and commodity prices. Also during this time, the Scenario 8 reference case was created to better capture the impacts of the recent economic recession. Figure 6-3 has more details on that scenario. In other cases, suggestions received from the SRG and general public were incorporated into the analysis. The modeling and evaluation processes were also carefully examined and changes were made to further improve the quality of the analysis.

6.6 Identification of Recommended Planning Direction

After the Draft IRP public comment period, efforts continued to prepare the final IRP. The primary deliverable for this phase was the identification of the Recommended Planning Direction. This strategy will help define TVA's short- and long-term strategic direction and identify short-term actions that need to be accomplished. The preparation of the final IRP consisted of the following steps:

1. Identification of key components
2. Definition of boundary conditions
3. Development of Recommended Planning Direction candidates
4. Identification of the Recommended Planning Direction

6.6.1 Identification of Key Components

Components of the preferred planning strategies from the Draft IRP were evaluated for characteristics that would likely comprise the Recommended Planning Direction.

The revised approach reduced the number of inputs that were included in model optimization to produce a more focused result while allowing other unique combinations of resources to be tested that were not directly considered in the Draft IRP.

A key variable that was retained as a defined input was the level of idled coal-fired capacity. Idled capacity was not optimally selected within the model runs and required model iterations to test the different levels. This constraint meant that the optimum renewable and EEDR portfolio amounts were then selected for each assumed level of idled coal-fired capacity.

Portfolios for renewable additions and EEDR levels were optimized in the final analysis, along with the components identified in the Draft IRP. The model selected the best renewable and EEDR portfolio from the iterations provided as a part of optimizing all other resource alternatives.

6.6.2 Definition of Boundary Conditions

As described above, the Recommended Planning Direction was identified based on a blended optimization analysis using certain components from Strategies B, C and E. Figure 6-11 outlines the boundary conditions used in this stage of the analysis.

Components	Boundaries
EEDR	The EEDR portfolio will be no less than 2,100 MW & 5,900 annual GWh reduction by 2020
Renewable additions	Renewable additions will be no less than the existing wind contracts
Coal-fired capacity idled	Coal-fired capacity idled will be between 2,400 MW and 4,700 MW
Energy storage	The pumped-storage hydro unit (850 MW) will be included in all cases
Nuclear	Nuclear units cannot be added any earlier than 2018 and large units must be a minimum of two years apart – B&W technology at BLN cannot be added any later than 2020
Coal	New units cannot be added prior to 2025 and must be equipped with carbon capture and sequestration
Market purchases and transmission	If more than 900 MW/year are purchased beyond current contracts and extensions, potential transmission costs should be considered
Transmission	Transmission upgrades will be made to support new supply resources and maintain system readability

Figure 6-11 – Recommended Planning Direction Boundary Conditions

Within these boundaries, the capacity optimization model selected a resource plan that met the study constraints for reliability and least cost. To identify the optimum resource plan, multiple iterations were run within the model using the ranges of EEDR, renewable additions and idled coal-fired capacity as shown in Figure 6-12.

Components	Range of Options Tested				
EEDR	2,100 MW & 5,900 annual GWh reductions by 2020	3,600 MW & 11,400 annual GWh reductions by 2020	5,100 MW & 14,400 annual GWh reductions by 2020		
Renewable additions	1,500 MW competitive resources or PPAs by 2020	2,500 MW competitive resources or PPAs by 2020	2,500 MW competitive resources or PPAs by 2029	3,500 MW competitive resources or PPAs by 2020	3,500 MW competitive resources or PPAs by 2029
Coal-fired capacity idled	2,400 MW total fleet reductions by 2017	3,200 MW total fleet reductions by 2017	4,000 MW total fleet reductions by 2017	4,700 MW total fleet reductions by 2017	

Figure 6-12 – Recommended Planning Direction Range of Options Tested

Figure 6-12 also indicates the coal-fired capacity idling levels that were studied. As previously stated, these levels were *not* selected by the optimization model based on the full incremental costs of retaining these assets as part of the portfolios, but functioned as defined model inputs. As a result, the options shown for renewables and EEDR, along with any other resource options, were available for selection during optimization for each of the four assumed coal-fired idling levels.

6.6.3 Development of Recommended Planning Direction Candidates

Optimization results were produced by testing the four coal-fired idling levels across a subset of the scenarios originally developed for the Draft IRP.

The following scenarios were used to efficiently test the full range of possible futures for a total of 12 optimized cases:

- Scenario 1 – represented the upper bound
- Scenario 8 – represented a mid range of possible futures
- Scenario 3 – represented the lower bound and did not include climate change regulation

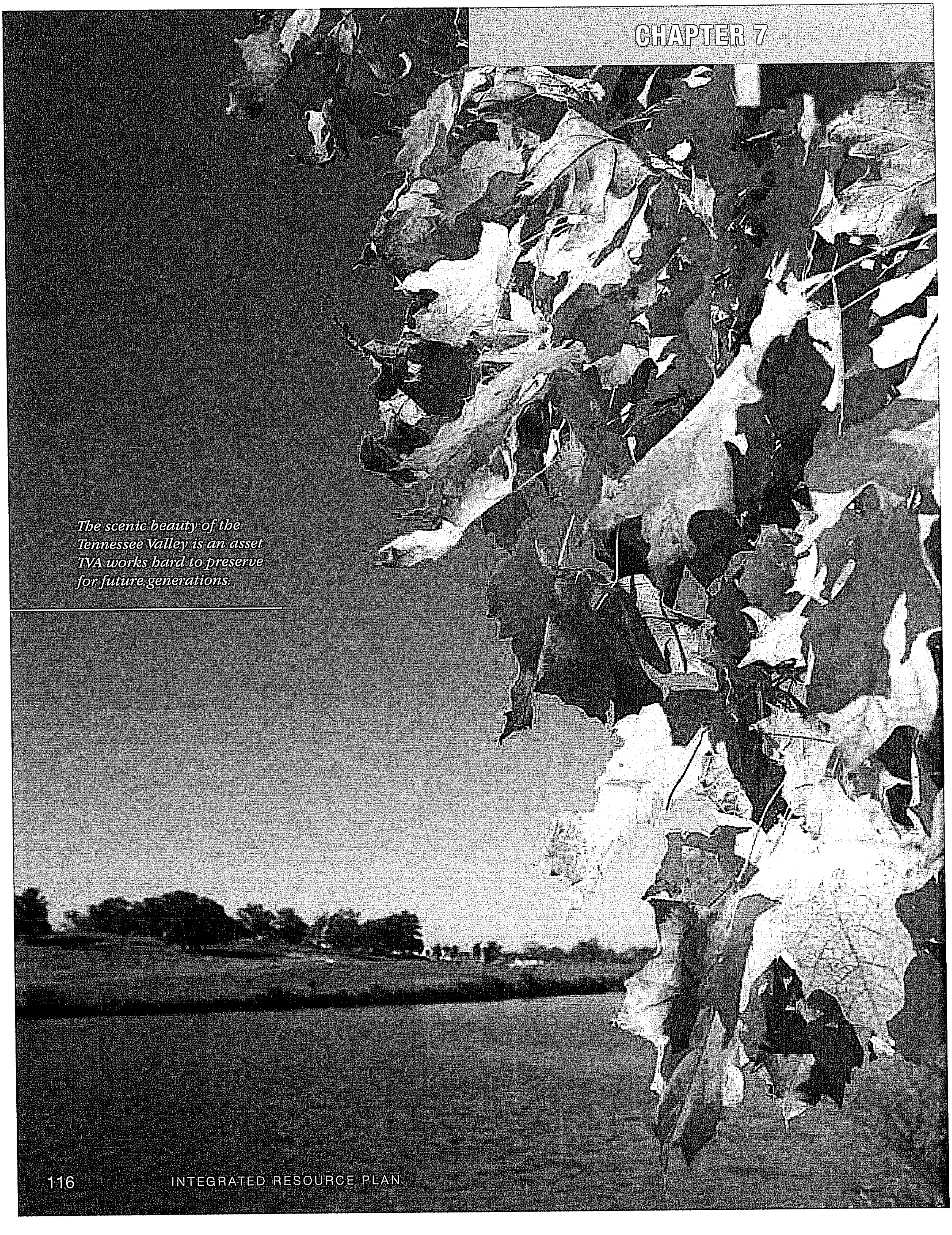
The following iterative six-step approach was used to produce the case results for the final IRP:

1. Incremental changes were made to strategy components in an attempt to improve upon the preferred planning strategies identified in the Draft IRP
2. The new strategy was tested in Scenarios 1 – 8 to evaluate new component combinations
3. The results were rescored to build a fully populated scorecard with ranking and strategic metrics
4. The completed scorecard was compared with results in the Draft IRP and previously considered alternatives to identify improvement, if any
5. Components common to strategies that exhibited improvement were selected to describe the proposed Recommended Planning Direction
6. Steps 1-5 were repeated until no further improvements were identified

6.6.4 Identification of Recommended Planning Direction

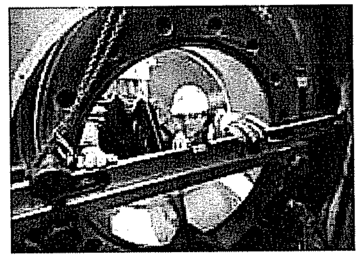
A Recommended Planning Direction was identified and is fully described in Chapter 8 – Final Study Results and Recommended Planning Direction. The identification of the Recommended Planning Direction was an iterative process that utilized the results of more than 3,000 modeling runs and evaluation of the results. The scorecard, along with stakeholder input and other considerations, was used to identify changes from the preferred planning strategies identified in the Draft IRP.

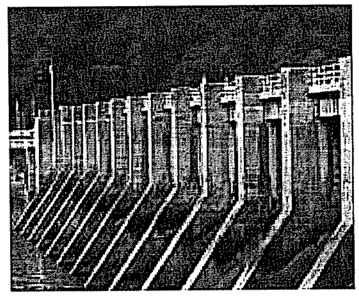
Resource Plan Development and Analysis



The scenic beauty of the Tennessee Valley is an asset TVA works hard to preserve for future generations.

Draft Study Results





The Guntersville Dam in Marshall County, Ala., has a generating capacity of 140,400 kilowatts of electricity.

Draft Planning Scenarios and Strategies

Scenario
1 Economy Recovers Dramatically
2 Environmental Focus is a National Priority
3 Prolonged Economic Malaise
4 Game-Changing Technology
5 Energy Independence
6 Carbon Regulation Creates Economic Downturn
7 Reference Case: Spring 2010

Planning Strategy
A Limited Change in Current Resource Portfolio
B Baseline Plan Resource Portfolio
C Diversity Focused Resource Portfolio
D Nuclear Focused Resource Portfolio
E EEDR and Renewables Focused Resource Portfolio

7 Draft Study Results

This chapter describes the results and findings from the Draft IRP, published in September 2010. The Draft IRP studied five strategies in a total of six scenarios and one reference case scenario. As a result, 35 distinct 20-year portfolios or capacity expansion plans were created. These portfolios were scored and the results were evaluated as described in Chapter 6 – Resource Plan Development and Analysis. Results of this IRP are fully described in Chapter 8 – Final Study Results and Recommended Planning Direction

7.1 Analysis Results

7.1.1 *Firm Requirements and Capacity Gap*

Forecasted capacity needs for the range of scenarios considered were presented in Section 4.3 – Estimate Supply. Consistent with TVA's scenario planning approach, variations from the expected forecast were studied as well. These variations were grouped into scenarios that represented different plausible futures in which TVA may have to operate. The key components of each scenario were translated into a forecast of firm requirements (demand plus reserves), which was used to identify the resulting capacity gap and need for power, driving the selection of resources in the capacity planning model.

Figure 7-1 illustrates the firm requirements forecasts for the seven scenarios that were studied in the Draft IRP. Six of the seven scenarios were specifically designed for the IRP study and are discussed in Section 6.1 – Development of Scenarios and Strategies. The seventh scenario represented the spring 2010 market view and was considered the reference case for analysis in the Draft IRP.

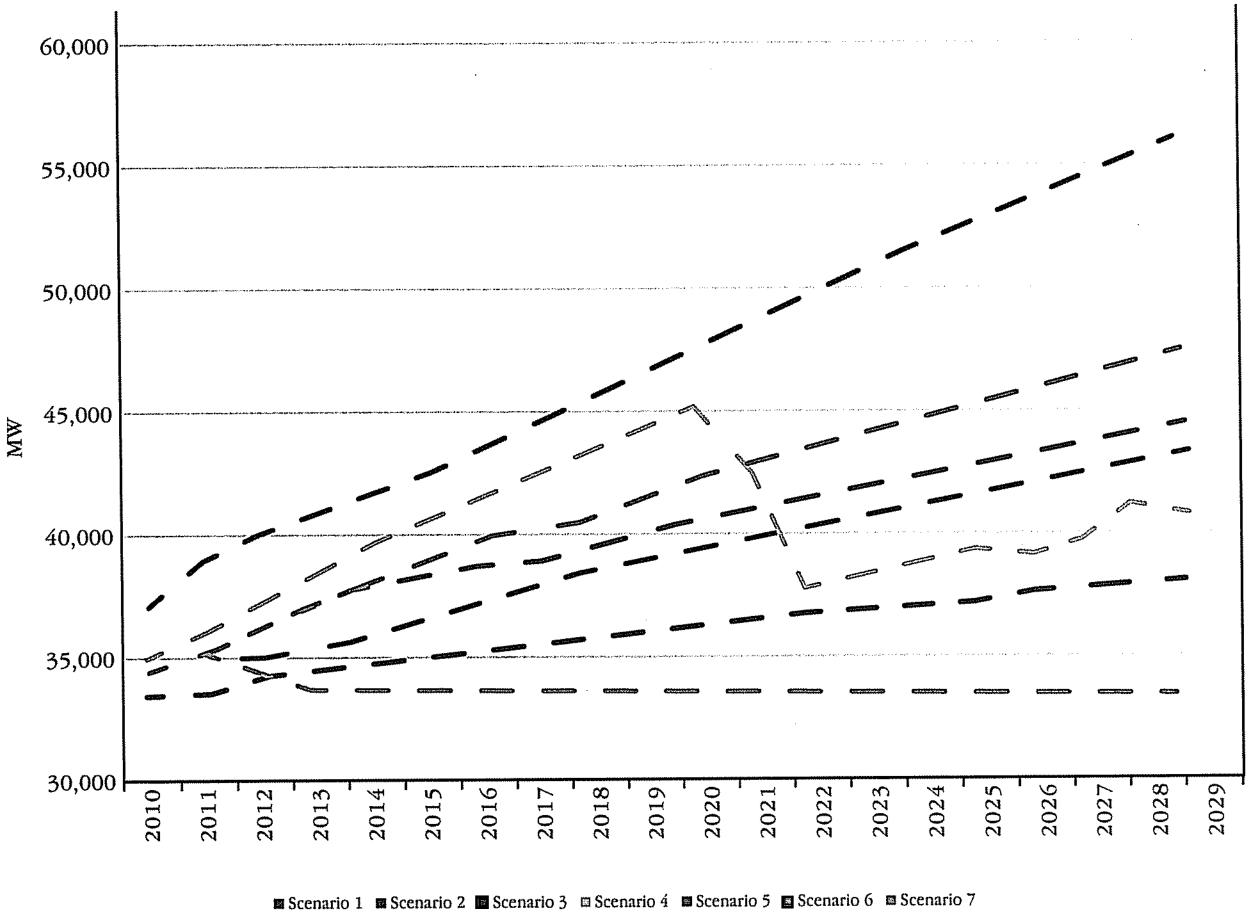


Figure 7-1 – Firm Requirements by Scenario

Firm requirements were greatest in Scenario 1 (highest load growth scenario) and lowest in Scenario 6 (flat to slightly negative load growth). The remaining scenarios fell within this range and generally displayed smooth but unique growth trends, with the exception of Scenario 4 (game-changing technology scenario). Firm requirements for Scenario 4 experienced a dramatic drop in load in 2021, reflecting that scenario's assumptions of rapid commercialization of alternative technologies displacing the need for traditional resources.

The shape of the firm requirements curves influenced the type and timing of resource additions in the strategies, especially in Scenario 4 where resource additions were reduced or eliminated in the latter years. The timing of additional resources was a function of the existing system capacity and the impact of the defined model inputs for each strategy.

Figure 7-2 summarizes the range of the capacity gaps at the end of the study period for the cases studied in the Draft IRP. The range of the capacity gaps in this figure is based on the minimum and maximum gaps found in the five planning strategies developed for the Draft IRP. The maximum gap represents the largest capacity gap and is based on Scenario 1. The minimum gap represents the smallest capacity gap or potentially a surplus of generation and is based on Scenario 6.

Strategy	Max Capacity Gap (MW)	Min Capacity Gap (MW)
A	18,000	(4,800)
B	20,000	(3,000)
C	17,000	(6,000)
D	19,000	(4,000)
E	18,000	(5,000)

Figure 7-2 – Range of Capacity Gaps by Strategy

This broad range of capacity gaps resulted in a wide range of expansion plans across the 35 portfolios developed in the Draft IRP.

7.1.2 Expansion Plans

The amount and type of resource additions for the five planning strategies that were evaluated in the Draft IRP are consistent with the following assumptions that define each of the scenarios:

- The largest amount of resource additions occurred in Scenario 1
- Scenario 7, representing the Reference Case: Spring 2010, required an average amount of new resources over the study period
- Scenarios 3 and 6 had the least amount of resource additions
- Small amounts of new resources were added in Scenarios 2 and 5
- In Scenario 4, no resources were added after 2020, consistent with the dramatic drop in load beginning in 2021

The individual capacity expansion plans for each of the five planning strategies are presented in Appendix E – Draft IRP Phase Expansion Plan Listing, and are grouped by scenario. These plans reflect the contributions from the TVA Board of Directors' approved projects. In addition, the impacts of the defined model inputs, particularly the capacity associated with the renewable resource portfolios and the avoided capacity value from EEDR, are also included. Figure 7-3 illustrates the range of capacity additions by resource type across all the strategies.

Type	Minimum (MW)[1,2]	Maximum (MW)[1,3]
Nuclear	0	4,754 (4)
Combustion turbine	0	8,092 (11)
Combined cycle	0	6,700 (7)
IGCC	0	934 (2)
SCPC	0	800 (1)
Avoided capacity (EEDR)[4]	1,905	6,361
Renewables[4]	160	1,157
Pumped-storage[4]	0	850
Coal-fired capacity idled[4]	0	7,000

Notes:

1 – Values shown are for dependable capacity at the summer peak. Nameplate capacity of renewables range from 1,300 to 3,500 MW

2 – Minimums exclude Board-approved projects (WBN 2, JSFCC, and Lagoon Creek)

3 – Number of units shown in ( )

4 – Defined model input

Figure 7-3 – Capacity Additions by 2029

To provide a different view of the expansion plan results for the strategies evaluated in the Draft IRP, a set of histograms was developed that presents data on the frequency of selection of key resource types across the 35 portfolios. Figures 7-4 through 7-7 are plots that illustrate the number of portfolios and the specific number of nuclear, coal, combined cycle and combustion turbine units that may be added.

Nuclear capacity beyond Watts Bar Unit 2 was prominent in the analysis results, as illustrated in Figure 7-4. At least two nuclear units, and up to four, were added in 19 of the 28 possible portfolios, and the first nuclear unit was added between 2018 and 2022. Nuclear capacity was not added to portfolios in scenarios with nearly flat load growth. In one strategy, nuclear was not a permitted resource expansion option.

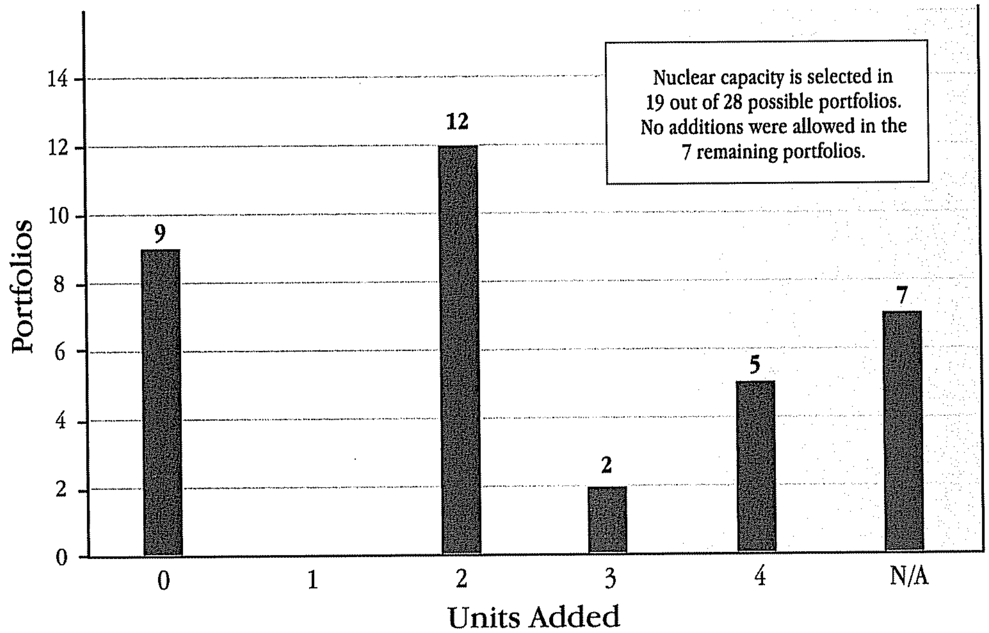


Figure 7-4 – Number of Nuclear Units Added

Coal capacity additions were very infrequent (Figure 7-5). Integrated gasification combined cycle (IGCC) units with carbon capture were selected only after 2025 and in just three of the 21 possible portfolios. Supercritical pulverized coal (SCPC) with carbon capture was added after 2035 and in only one of the 21 possible portfolios. Two strategies do not permit additional coal-fired units.

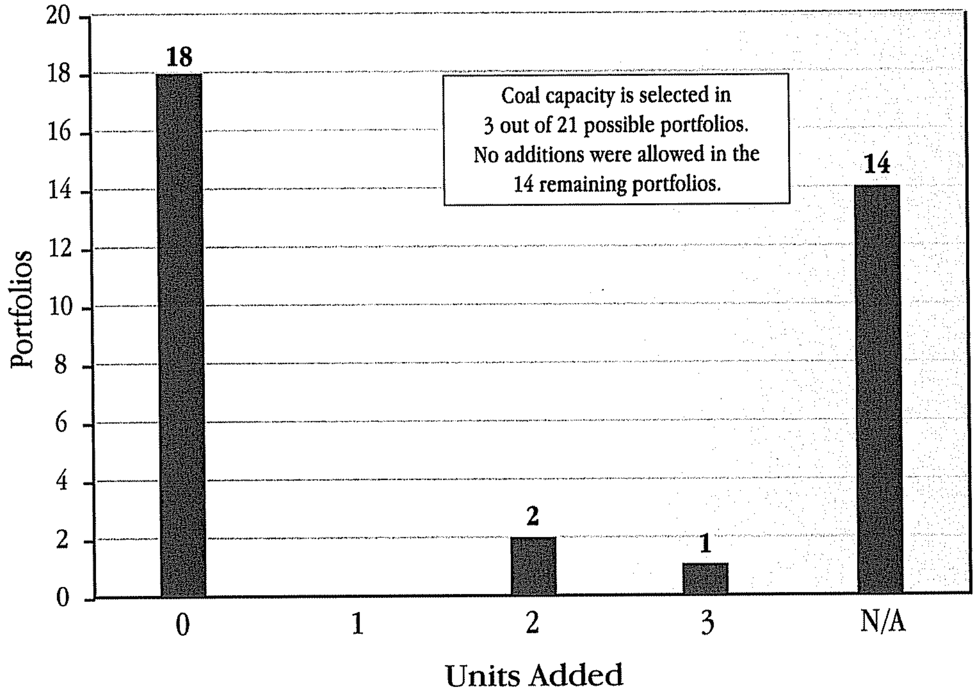


Figure 7-5 – Number of Coal Units Added

Additions of combined cycle capacity (including potential acquisitions of IPP projects) ranged from 0–7 units (0-6,700MW) as shown in Figure 7-6. Combined cycle capacity was selected in 15 of 28 possible portfolios.

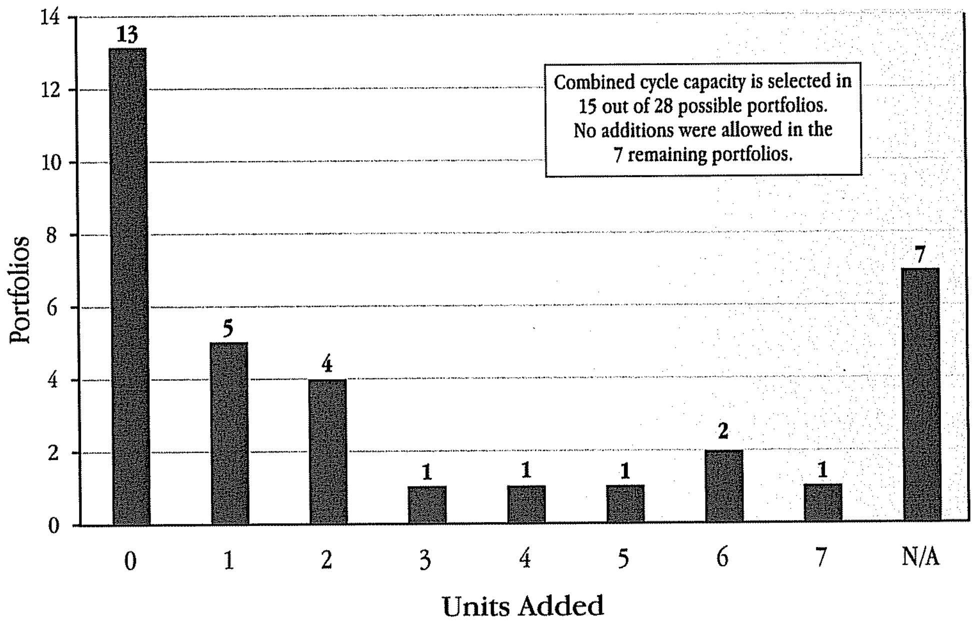


Figure 7-6 – Number of Combined Cycle Units Added

As illustrated in Figure 7-7, combustion turbine capacity additions ranged from 0–11 units (0-8,000 MW) and the majority of portfolios that selected combustion turbine capacity added just a single unit. Natural gas capacity (CT/CC) was not selected for portfolios in scenarios with nearly flat load growth or scenarios with the largest avoided capacity from EEDR.

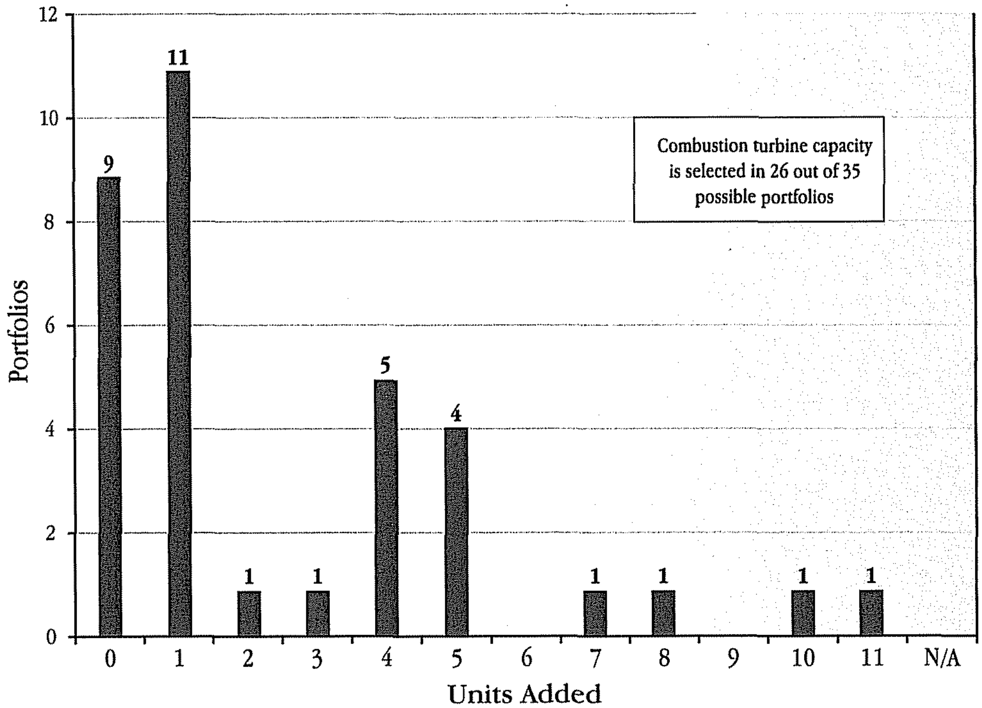


Figure 7-7 – Number of Combustion Turbine Units Added

7.1.3 System Energy Mix

Figure 7-8 lists the minimum and maximum percentage contributions to total energy production by type in 2029 from the 35 portfolios produced in the Draft IRP. Values represent the highest and lowest percentages for each type and are not from a single portfolio; therefore, they do not add to 100 percent.

Type	Minimum	Maximum
Combined Cycle	0%	13%
Combustion Turbine	0%	3%
Nuclear	27%	47%
Coal	24%	47%
Renewables	2%	8%
EEDR (savings)	2%	11%

Figure 7-8 – Range of Energy Production by Type in 2025

Nuclear and coal had the greatest swings in percentage contribution to total energy. In the majority of scenario and strategy planning combinations, nuclear overtook coal to produce the greatest percentage of total energy. Strategy A is the exception with coal remaining the largest energy producer in that strategy.

7.1.4 Plan Cost and Risk

A comparison of the expected value of PVRR by scenario for the strategies evaluated in the Draft IRP is illustrated in Figure 7-9. Scenario 1 resulted in the highest value for PVRR, while the lowest PVRR values were found in Scenario 6. Within each scenario, Strategy D generally produced the highest cost portfolios due to the larger amount of coal-fired capacity idled that must be replaced by new resources. Strategy A resulted in the set of portfolios with the next highest cost, caused by retaining a higher level of coal-fired capacity compared to other strategies, exposing it to more significant CO_2 compliance costs. Strategy C produced the lowest PVRR values in six of the seven scenarios. However, Strategy C was near the middle of the pack on short-term rate impacts which are discussed in the next section.

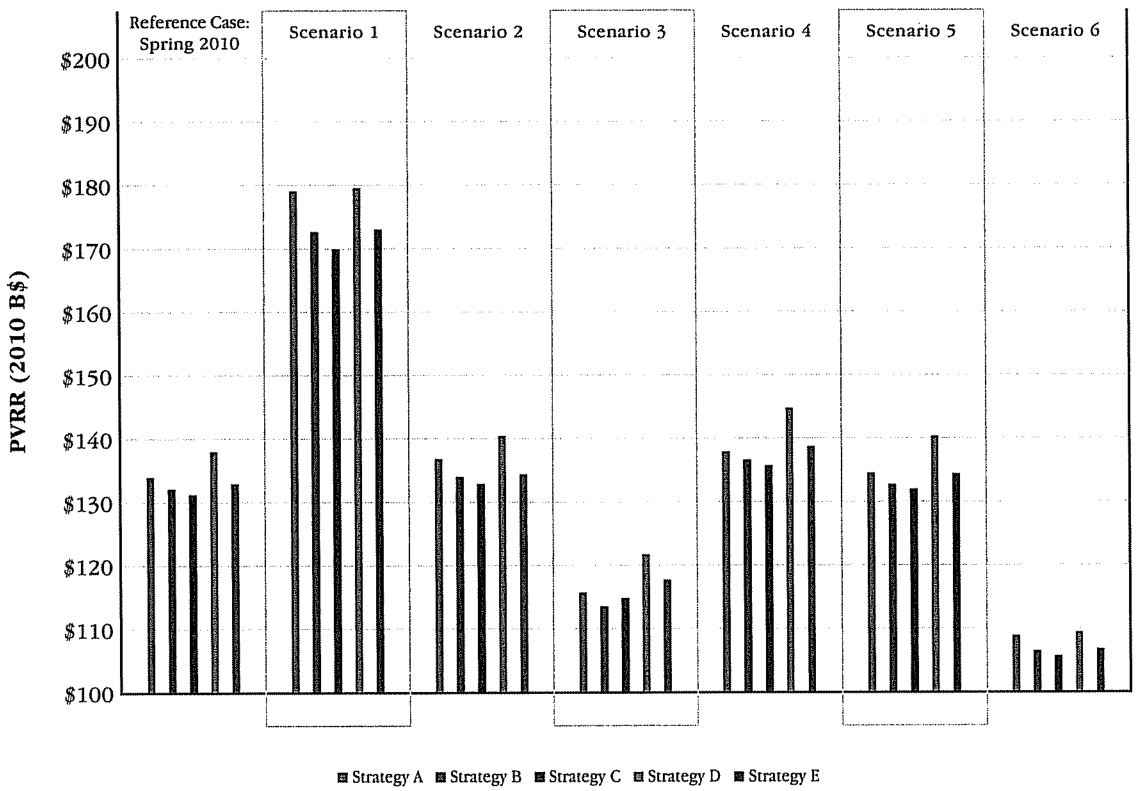


Figure 7-9 – Expected Value of PVRR by Scenario

Figure 7-10 presents the short-term rate impacts (average system costs) by scenario. The strategy with the highest expected value of short-term rates was Strategy D because this strategy had the most new capacity additions in the 2011–2018 timeframe. Strategy A produced the lowest short-term rate values in five of the seven scenarios because no new capacity was added to any portfolios within that strategy. However, Scenarios 3 and 6 included higher CO_2 compliance costs, which drove up the cost of the coal-heavy portfolios in Strategy A (in those scenarios). Strategy A's exclusive reliance on the market to serve load growth also has greater risk as shown in the discussion of risk metrics in the next section.

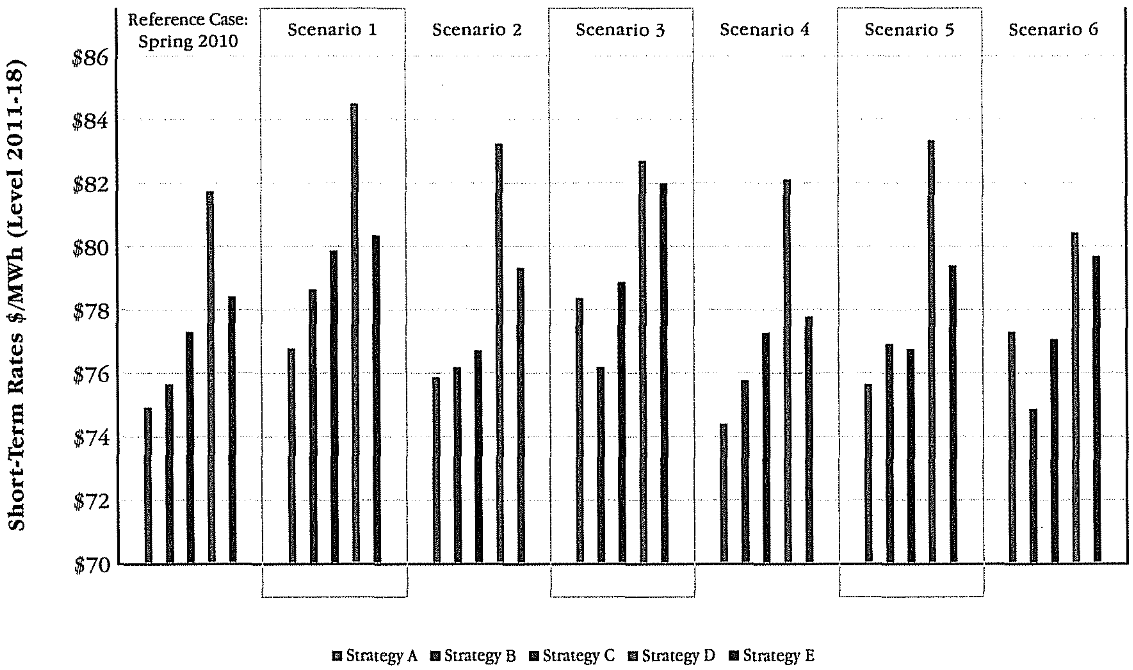


Figure 7-10 – Expected Values for Short-Term Rates by Scenario

Figures 7-11 and 7-12 compare the two risk metrics for the planning strategies. Lower ratios indicated less risky portfolios based on the probability distributions of the portfolio PVRR values. The relative relationship across the scenarios for both the risk ratio and the risk/benefit ratio were consistent. The highest values occurred in Scenario 1, the risk ratio was lowest in Scenario 3 and the risk/benefit ratio was lowest in Scenario 6.

In both cases, these low values were caused by much lower load forecasts in those scenarios, which resulted in lower PVRR values with more narrow probability distributions. Strategy A had the highest risk profile in five of the seven scenarios, which was caused by the retention of coal-fired capacity. Strategy C was the least risky strategy in six of the seven scenarios due to its generally balanced resource mix.

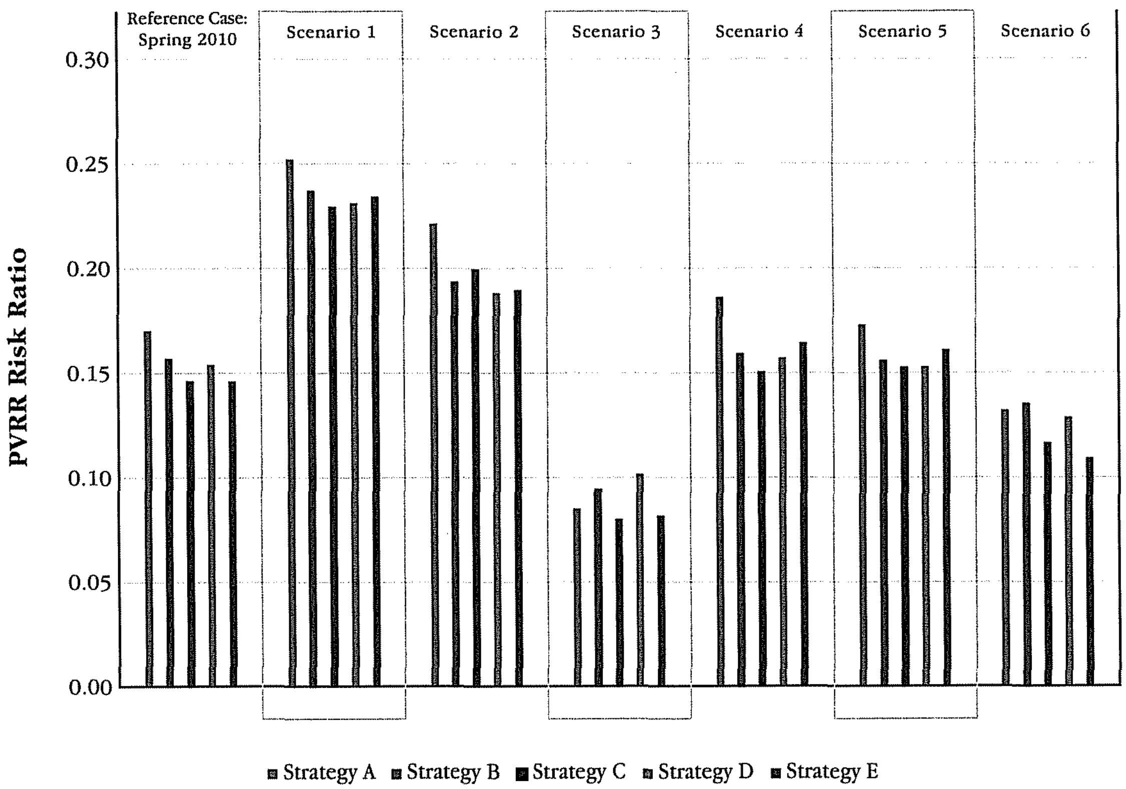


Figure 7-11 – PVRR Risk Ratio by Scenario

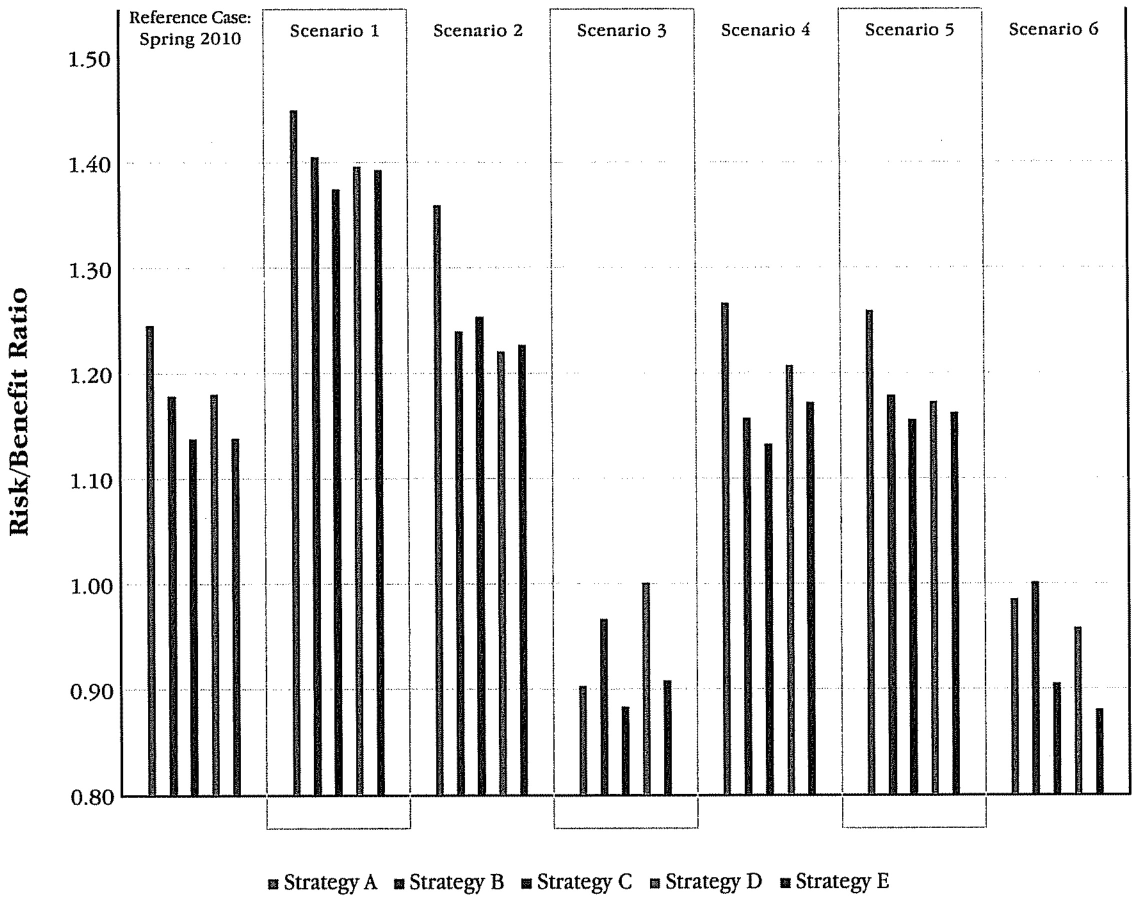


Figure 7-12 – PVRR Risk/Benefit by Scenario

7.2 Selection Process

The process that was used to rank and identify the preferred planning strategies was discussed in Chapter 6 – Resource Plan Development and Analysis. That process involved the following four steps:

1. Planning strategies were scored (based on cost and risk metrics) and ranked
2. Strategic metrics were added to the ranking metrics to complete the scorecard for the top ranked strategies
3. Selected strategies were released for public comment in the Draft IRP and the associated EIS
4. Sensitivity analyses were done as a result of public comments

The ranking of each strategy was based on the expected values of the cost and risk metrics generated by the stochastic analysis, which is described in Chapter 6 – Resource Plan Development and Analysis. The expected values were translated into a score, and the scores across all seven scenarios were combined to produce a total strategy score. Strategies were ranked based on total score from highest to lowest. A subset of strategies was selected for further consideration based on scores and other strategic considerations such as potential environmental impacts.

7.2.1 Scorecard Results

Scorecards were generated by translating the expected values from the modeling results into a standardized score that was summed across the scenarios for each planning strategy. Figure 7-13 summarizes the average expected values of PVRR, short-term rates, risk/benefit and risk computed for the five planning strategies in each of the seven scenarios.

		Scenarios							
	Strategy	1	2	3	4	5	6	7	Average
Average of PVRR (2010 B $)	A	180	137	116	138	135	109	134	**136**
	B	179	136	114	137	133	107	133	**134**
	C	175	133	114	135	131	105	130	**132**
	D	181	137	115	138	134	103	132	**134**
	E	174	131	115	136	131	104	130	**132**
Average of ST Rates (level 2011-18)	A	76.82	75.92	78.42	74.47	75.75	77.31	74.97	**76.24**
	B	82.49	77.49	76.22	75.88	77.04	74.91	75.72	**77.11**
	C	83.57	74.60	77.40	76.00	75.64	75.55	75.94	**76.96**
	D	84.83	79.54	75.24	75.98	76.80	72.70	75.13	**77.17**
	E	78.91	75.94	78.23	74.78	76.01	75.90	75.14	**76.42**
Average of Risk/Benefit	A	1.45	1.36	0.91	1.27	1.26	0.99	1.25	**1.21**
	B	1.43	1.24	0.97	1.16	1.18	1.00	1.18	**1.17**
	C	1.41	1.29	0.89	1.14	1.16	0.91	1.14	**1.14**
	D	1.45	1.26	1.06	1.25	1.20	1.00	1.23	**1.21**
	E	1.42	1.24	0.93	1.19	1.18	0.90	1.15	**1.15**
Average of Risk	A	0.25	0.22	0.09	0.19	0.19	0.13	0.17	**0.18**
	B	0.23	0.19	0.10	0.16	0.17	0.14	0.16	**0.16**
	C	0.23	0.20	0.08	0.15	0.17	0.12	0.15	**0.16**
	D	0.23	0.19	0.11	0.17	0.18	0.14	0.16	**0.17**
	E	0.24	0.20	0.08	0.17	0.17	0.11	0.15	**0.16**

Figure 7-13 – Ranking Metrics Worksheet

After applying the methodology for translating actual values into color-coded scores, which is described in Chapter 6 – Resource Plan Development and Analysis, a scorecard was produced for each of the five planning strategies. In Figure 7-14, planning Strategy A was used to demonstrate how scores were computed and then summed to produce the total ranking score.

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/Benefit	Risk	Ranking Metric Score
1	93.87	100.00	95.07	91.26	94.82
2	95.76	99.25	90.32	85.74	93.61
3	98.28	95.78	98.39	94.38	96.84
4	97.49	100.00	88.75	77.41	92.42
5	97.09	99.85	91.73	87.21	94.81
6	94.14	93.66	90.08	80.82	90.51
7	96.74	100.00	90.59	85.43	94.15
				Total Ranking Metric Score:	657.15

Total Ranking Metric Score=Sum of Ranking Metrics Scores for all seven scenarios

Ranking Metric Score=65%*(65%*PVRR + 35%*ST Rate) + 35%*(35%*Risk/Benefit + 65%*Risk)
=65%*(65%*97.09 + 35%*99.85) + 35%*(35%*91.73 + 65%*87.21)=94.81

Legend
Better

Figure 7-14 – Planning Strategy A – Limited Change in Current Resource Portfolio

Scorecards for the remaining four strategies are shown in Figures 7-15, 7-16, 7-17 and 7-18.

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	97.71	97.59	98.40	97.34	97.68
2	97.76	98.85	100.00	99.98	98.79
3	99.61	98.70	91.37	83.79	94.79
4	98.38	98.11	98.25	93.79	97.26
5	98.44	98.14	98.61	98.94	98.51
6	96.55	96.96	88.56	78.46	91.55
7	98.01	99.01	96.50	94.26	97.20
				Total Ranking Metric Score:	**675.78**

Legend	
	Better

Figure 7-15 – Planning Strategy B – Baseline Plan Resource Portfolio

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	100.00	97.48	100.00	100.00	99.43
2	99.58	100.00	96.20	96.17	98.49
3	100.00	97.13	100.00	100.00	99.35
4	100.00	97.94	100.00	100.00	99.53
5	100.00	100.00	100.00	100.00	100.00
6	98.59	96.09	98.19	93.22	96.75
7	100.00	98.71	100.00	100.00	99.71
				Total Ranking Metric Score:	693.25

Legend	
	Better

Figure 7-16 – Planning Strategy C – Diversity Focused Resource Portfolio

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	97.40	97.54	96.41	96.81	97.18
2	97.90	98.51	99.04	98.90	98.40
3	99.41	100.00	81.31	69.12	90.43
4	97.40	97.97	90.14	92.05	95.42
5	97.86	98.47	96.57	92.60	96.64
6	100.00	100.00	89.16	78.46	93.77
7	98.56	99.79	92.15	91.33	96.41
				Total Ranking Metric Score:	668.26

Legend	
	Better

Figure 7-17 – Planning Strategy D – Nuclear Focused Resource Portfolio

	Ranking Metrics				
Scenarios	PVRR	Short-Term Rate Impact	Risk/ Benefit	Risk	Total Plan Score
1	99.43	99.21	97.82	96.78	98.58
2	100.00	99.22	99.79	100.00	99.80
3	99.15	96.03	95.91	97.73	97.72
4	99.45	99.58	95.32	89.57	96.73
5	99.83	99.50	98.87	99.47	99.56
6	99.16	95.61	100.00	100.00	98.64
7	99.68	99.77	98.98	98.96	99.45
				Total Ranking Metric Score:	690.47

Legend	
	Better

Figure 7-18 – Planning Strategy E – EEDR and Renewables Focused Resource Portfolio

The scores assigned to each strategy and the associated color coding was done within a given scenario. To properly interpret the scoring for each strategy, the values for each individual ranking metric in all five strategies were compared within a particular scenario.

7.2.2 Ranking of Strategies

Detailed descriptions of strategies were introduced in Chapter 6 – Resource Plan Development and Analysis. Figure 7-19 shows the rank order of the five planning strategies evaluated in the Draft IRP based on the total ranking metrics scores. The total strategy scores range from 657 to 693 out of a possible 700 points.

Rank	Planning Strategy	Preliminary Observations
1	C	• Performs the best against PVRR and risk metrics • Near the median for short-term rates
2	E	• Near the median for short-term rates • Performs near the best for PVRR
3	B	• Ranks near the median for PVRR, short-term rates and risk
4	D	• Ranks below the median for PVRR, rates and risk
5	A	• Performs the worst on PVRR and risk • Ranks the best for short-term rates in some scenarios

Figure 7-19 – Planning Strategy Ranking Order

A key element of a "no-regrets" strategy is that a portfolio performs relatively well in most scenarios, not just the reference case scenario. Using the initial planning results, Strategy C was the top-ranked planning strategy on the basis of the total ranking metric score. However, the separation between the scores of Strategies C and E was not statistically significant. Strategy C represented an attempt to define a balanced approach to the resource mix and performed best in five of the seven scenarios based on total plan score, performed second best in another and third in just one scenario. The ranking metrics implied that Strategy C was the most robust in many possible futures. Strategy C was the top performer for PVRR and for both risk metrics. It performed reasonably well on short-term rates, but it was not the best strategy in that category.

The second best planning strategy, based on total ranking metric score, was Strategy E. As with Strategy C, this strategy represented an expanded commitment to cleaner resource options, especially pertaining to EEDR and renewable energy options. The strategy performed well in all four of the ranking metrics and performed best in two of the seven scenarios based on total plan score, resulting in a total strategy score that was very close to Strategy C.

The third best planning strategy was Strategy B. This strategy represented a "business-as-usual" approach that did not significantly deviate from existing portfolio mixes over the long term. This strategy performed reasonably well with scores in the four ranking metrics that were in the mid range for each metric, but did not rank first in any of the scenarios.

Strategy B was retained for further analysis in this IRP as a baseline strategy for impact analysis.

Strategies A and D were in the lower tier of the total strategy scores and did not represent options that offer preferable planning approaches. These two strategies represented approaches that tended to define the boundary conditions within which the other strategy results could be placed. Strategy A was an approach that included retention of all existing coal-fired capacity, with a high level of clean air capital and maintenance spending and heavy reliance on the market. The scorecard for this strategy showed it to be the worst performer in most metrics for most of the scenarios, except for the short-term rate metric where it performed quite well. Strategy D was characterized by the largest level of coal-fired capacity idled which called for the most new capacity additions. This resulted in poor strategy scores across the scenarios, although this strategy outperformed Strategy A.

7.2.3 Sensitivity Cases

In addition to the initial 35 portfolios developed from the five planning strategies, TVA also performed certain sensitivity analyses. These analyses focused on key assumptions within those strategies based on review of the scorecard results. In the Draft IRP, the sensitivity analyses consisted of four cases involving Strategies C and E (the top-ranked strategies based on the results to date). The characteristics of these sensitivity cases are described in Figure 7-20.

Sensitivity Description	Basis for Selection
C1 – Strategy C with pumped-storage hydro removed	Test for improvement in short-term rate impacts by removing defined model input for pumped-storage hydro unit
C2 – Same as Sensitivity C1 with no capacity additions prior to 2018	Test for improvements in short-term rate impacts by defining near-term capacity additions. Modeled after Strategy A, which performs the best on rates
E1 – Strategy E with greater (7,000 MW) coal-fired idling (same as Strategy D)	Test to see if largest values for EEDR, renewables, and coal unit idling significantly improve the PVRR and short-term rate impacts of Strategy E
E2 – Strategy E with lower (2,500 MW) renewable portfolio (same as Strategy C)	Improve PVRR and short-term rates by using the lower renewable portfolio applied in Strategy C

Figure 7-20 – Sensitivity Characteristics

When these sensitivity cases were evaluated using the same ranking metrics applied to the original five planning strategies, a new rank order of strategies was established, as shown in Figure 7-21. The scores now range from 655 to 689.

Rank	Planning Strategy
1	C1 – Strategy C without pumped-storage hydro
2	C – Diversity Focused Resource Portfolio
3	C2 – same as C1 with no capacity additions prior to 2018
4	E – EEDR and Renewables Focused Resource Portfolio
5	E2 – Strategy E with greater coal unit idling
6	E1 – Strategy E with lower renewable portfolio
7	B – Baseline Plan Resource Portfolio
8	D – Nuclear Focused Resource Portfolio
9	A – Limited Change in Current Resource Portfolio

Figure 7-21 – Rank Order of Strategies

Sensitivity C1 was a slight improvement over planning Strategy C and now has the highest-ranking metric score among the options considered in the Draft IRP. Sensitivity C2 was slightly lower than Strategy C. As components changed, the stability of Strategy C represented a noteworthy quality. Sensitivities E1 and E2 did not improve the results as compared to Strategy E and were removed from further consideration for the final IRP.

7.2.4 Other Strategic Considerations

In addition to the metrics used to establish the rank order of the planning strategies, TVA included strategic metrics in the fully populated scorecard. These strategic metrics included environmental and regional economic impact measures that recognize other aspects of TVA's mission. These strategic metrics are fully discussed in Chapter 6 – Resource Plan Development and Analysis. Note that for the economic impact measures, all of the IRP strategies were analyzed only for Scenarios 1 and 6 – the scenarios that defined the upper and lower range of strategy impacts within the scenario range.

Figure 7-22 shows the strategic metrics for each of the five planning strategies.

Planning Strategy A

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	○	◑	◑	0.1%	0.1%
2	○	◔	◔		
3	○	○	○		
4	○	◔	◑		
5	○	◔	◔		
6	○	○	◔	-0.4%	-0.4%
7	○	◔	◑		

Planning Strategy D

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	●	◕	●	1.2%	1.0%
2	●	◕	●		
3	●	●	●		
4	●	◕	●		
5	●	●	●		
6	◕	●	●	-0.1%	-0.2%
7	●	●	●		

Planning Strategy B

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	◔	○	○	1.0%	0.8%
2	◔	○	○		
3	◔	◔	◔		
4	◔	○	○		
5	◔	○	○		
6	◔	◔	○	-0.3%	-0.3%
7	◔	○	○		

Planning Strategy E

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	◕	●	◕	0.8%	0.6%
2	◕	●	◕		
3	◕	◕	◕		
4	◑	●	◕		
5	◕	◕	◕		
6	●	◕	◕	0.3%	0.2%
7	◕	◕	◕		

Planning Strategy C

	Strategic Metrics				
	Environmental Stewardship			Economic Impact	
Scenarios	CO_2 Footprint	Water	Waste	Total Employment	Growth in Personal Income
1	◑	◔	◔	0.9%	0.6%
2	◑	◑	◑		
3	◑	◑	◑		
4	◕	◑	◔		
5	◑	◑	◑		
6	◑	◑	◑	0.2%	0.1%
7	◑	◑	◔		

Legend	
●	Better
◕	↑
◑	
◔	
○	

Figure 7-22 – Strategic Metrics for Five Planning Strategies

Results of the CO_2 metric showed that Strategy D had the best performance (lowest emissions), followed by Strategies E, C, B and A. Each strategy showed a declining rate of emissions and the variance between each strategy was quite low since all coal-fired units that will remain in service are assumed to receive environmental controls. With that being said, all five strategies will be fully compliant with applicable air emissions regulations.

Results of the water metric indicated that Strategy D had the best performance, followed by Strategies E, C, A and B. Results of the waste metric show Strategy D had the best performance, followed by Strategies E, C, A and B. Additional information on all environmental metrics calculations can be found in Appendix A – Method for Computing Environmental Impact Metrics.

Based on the Draft IRP results, planning Strategies D and E had the best relative performance across the environmental metrics. Strategy C was average to slightly above average, and Strategies A and B had the lowest relative performance.

For the economic impact metrics, Strategy A was the worst performer. Strategies B, C, D and E had comparable results, within a few tenths of a percentage difference from the impacts computed for the reference portfolio (Strategy B in Scenario 7). Strategies C and E had very similar impacts, performing above the reference portfolio in the long term under both Scenarios 1 and 6.

Along with the strategic metrics, innovations that enable the utilization of key technologies in the planning strategies have been identified and summarized in Figure 7-23. The figure shows which of the five planning strategies would be impacted by each of the innovations in the future.

Technology Innovation	Description	A	B	C	D	E
Smart Grid Technologies	Advancements in this area are necessary to fully realize the EEDR benefits included in certain planning strategies		X	X	X	X
Transmission Design & Infrastructure	Improvements in transmission system devices to manage power flows and advancement in dc line technologies will be needed to facilitate power transfers and the import of additional wind-sourced power			X	X	X
Advanced Energy Storage	More research is needed to improve the design of pumped-storage hydro (PSH) and identify new storage technologies that might offer advantages similar PSH			X	X	X
Small Modular Nuclear Reactors	This technology may offer some flexibility for siting and operating nuclear capacity in those strategies that include a reliance on new nuclear capacity later in the planning period		X	X	X	X
Advanced Emission Controls for Coal-Fired Units	To enable full use of coal-fired resources, advances in emission controls (especially carbon capture and sequestration) are needed to achieve a more balanced long-term generation portfolio	X	X	X		

Figure 7-23 – Technology Innovation Matrix

TVA will closely monitor and possibly invest in these and other technology innovations during the planning period. The particular technology innovations that are necessary to implement the Recommended Planning Direction will likely shift as more information becomes available about each technology area and as power supply needs change.

In addition to the PVRR risk metrics discussed in Chapter 6 – Resource Plan Development and Analysis, there are other risks that were considered when evaluating the merits of alternative strategies. The financial risk measures included in the ranking metrics portion of the planning strategy scorecard may have indirectly accounted for some of these risks, but only in part. Examples of these broader, more difficult to quantify, risk considerations include:

- The ability of EEDR programs to stimulate distributor and customer participation and the programs' ability to deliver forecasted energy savings and demand reductions. The planning strategies with higher EEDR targets have a greater exposure to these risks
- The availability and deliverability of natural gas. There is finite capacity in the existing natural gas infrastructure. Risks of being limited by deliverability and availability will likely increase as natural gas generation capacity is increased
- The ability to achieve schedule targets for licensing/permitting, developing and constructing new generation capacity. Risks of meeting schedule targets will likely increase as the number and complexity of construction projects increase. In addition, projects with more extensive licensing/permitting requirements will likely have greater exposure to schedule risk
- The timely build-out of transmission infrastructure to support future resources. This is a particular concern with projects that may require transmission expansion outside of the TVA system, such as power purchase agreements for wind energy. Risks will likely increase as the amount of construction required increases and if that construction is undertaken by entities other than TVA
- Legislative and regulatory risks that could strand certain investments in coal-fired assets by, for example, applying a more stringent regulatory framework around coal-fired assets, or by mandating certain other types of generation, including renewables, that could crowd out existing sources of generation
- Game-changing technologies, either on the supply or demand side, that could either dramatically increase (i.e., new sources of demand) the need for electricity or dramatically decrease (i.e., distributed generation) the need for electricity in the long term

The list above is not intended to be exhaustive. It provides examples of other strategic components that TVA considered when it identified the preferred planning strategies in the Draft IRP as well as the Recommended Planning Direction in the final IRP. In addition, the analysis results and public input were considered. TVA encouraged those commenting on the Draft IRP to provide information about and share their views on these other risks.

7.3 Preferred Planning Strategies

Based on the Draft IRP results, TVA retained the top three ranked planning strategies for further analysis for the final IRP (Chapter 8 – Final Study Results and Recommended Planning Direction). Strategies C, E and B were retained from the Draft IRP to be subjected to additional analysis and sensitivity testing in an effort to determine improved combinations of planning components.

Illustrative portfolios (20-year resource plans) were identified as part of the evaluation. In the Draft IRP, a broad set of portfolios were identified that corresponded to the three planning strategies that were retained in the Draft IRP.

Four representative resource portfolios were selected from planning Strategies C, E and B. The 12 implementing portfolios for the Draft IRP are shown in Figure 7-24. These portfolios described a relatively broad set of resource plan options that were subjected to additional analysis before completing the final IRP. Portfolios produced in Scenario 1 represented the largest amount of new resource additions, while those produced in Scenario 3 represented the least amount of new resources that could be added over the planning period.

Year	Planning Strategy C				Planning Strategy E				Planning Strategy B			
	SC 1	SC 2	SC 3	SC 7	SC 1	SC 2	SC 3	SC 7	SC 1	SC 2	SC 3	SC 7
2010	PPAs & Acq				PPAs & Acq				PPAs & Acq			
2011												
2012	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	CTa								CTa CT GL CT Ref			
2015	CT GL CT Ref CC			GL CT Ref CC	GL CT Ref CTa CC (2)			GL CT Ref CC	CT CC	GL CT Ref		GL CT Ref CTa MKT
2016	CT			MKT	CT			MKT	CT			CT MKT
2017	MKT			MKT				MKT	CT			CTa MKT
2018	BLN1			BLN1	CT			CC	BLN1			BLN1
2019	MKT				CC				CT	BLN1		
2020	BLN2 PSH	PSH	PSH	BLN2 PSH	CC			MKT	BLN2			BLN2
2021	CT				CTa			MKT	CC	BLN2		
2022	CC MKT	BLN1			BLN1 MKT	BLN1		BLN1 MKT	CT CC			CC
2023	CC MKT				CT MKT			MKT	CT			CT
2024	NUC	BLN2		MKT	BLN2	BLN2		BLN2	NUC MKT			
2025	IGCC			CT	CT				IGCC	NUC		CT
2026	NUC			MKT	CT			CT	NUC		MKT	MKT
2027	CT			CC	CT				CT	NUC	MKT	CT
2028	CT				NUC			CTa	CC		MKT	MKT
2029	IGCC CTa	NUC		CTa	CT			CTa	IGCC CTa	CTa	CTa MKT	CC

Defined Model Inputs	
Coal-fired capacity idled	3,252 MW by 2015
Renewable firm capacity	953 MW by 2029
	8,791 GWh by 2029
EEDR	4,638 MW by 2029
	14,032 GWh by 2029

Defined Model Inputs	
Coal-fired capacity idled	4,730 MW by 2015
Renewable firm capacity	1,157 MW by 2029
	12,251 GWh by 2029
EEDR	6,043 MW by 2029
	16,455 GWh by 2029

Defined Model Inputs	
Coal-fired capacity idled	2,415 MW by 2015
Renewable firm capacity	160 MW by 2029
	4,231 GWh by 2029
EEDR	2,520 MW by 2029
	7,276 GWh by 2029

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

IGCC = integrated gasification combined cycle (coal technology)

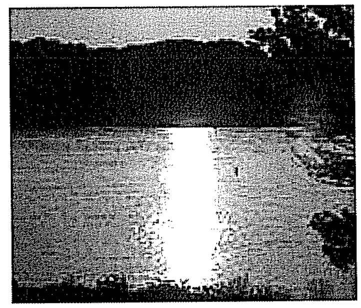
MKT = Purchased Power

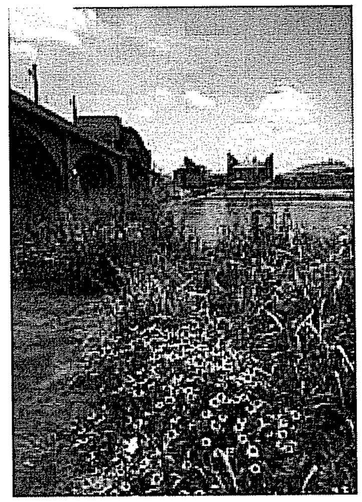
Figure 7-24 – Implementing Portfolios (Initial Phase)

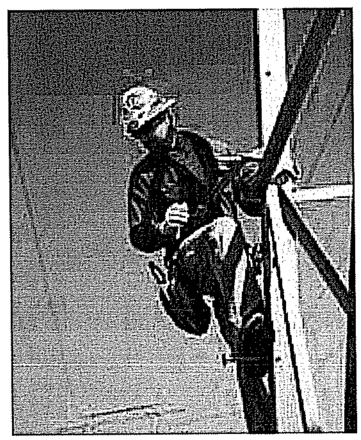
CHAPTER 8

Consumer energy efficiency and conservation will play a vital part of TVA's overall strategy for a greener future.

Final Study Results and Recommended Planning Direction







TVA's resource portfolio will continue to diversify in the future with the pursuit of new ways to harness renewable energy sources that are environmentally conscious and sustainable.

Scenarios and Strategies

Scenario	
1	Economy Recovers Dramatically
2	Environmental Focus is a National Priority
3	Prolonged Economic Malaise
4	Game-Changing Technology
5	Energy Independence
6	Carbon Regulation Creates Economic Downturn
7	Reference Case: Spring 2010
8	Reference Case: Great Recession Impacts Recovery

Planning Strategy	
A	Limited Change in Current Resource Portfolio
B	Baseline Plan Resource Portfolio
C	Diversity Focused Resource Portfolio
D	Nuclear Focused Resource Portfolio
E	EEDR and Renewables Focused Resource Portfolio
R	Recommended Planning Direction

8 Final Study Results and Recommended Planning Direction

TVA's IRP was developed in two major phases – the draft and final. The Draft IRP recommended retaining three of the five original planning strategies. This provided the starting point for the development of the final IRP in fall 2010. Considering updated forecast information and public comments, additional analyses were conducted with the goal of developing a "no-regrets" strategy. This was accomplished by fine-tuning and improving the strategies selected in the Draft IRP. The analyses included rescoring the ranking and strategic metrics in order to evaluate new component combinations identified in the analyses. This chapter describes the final analysis results and the Recommended Planning Direction that was produced by evaluating the analysis results, stakeholder input and other considerations.

8.1 Results Analysis

8.1.1 Firm Requirements and Capacity Gap

The final IRP used the same firm requirements and capacity gaps as discussed in Chapter 7 – Draft Study Results. In addition to the scenarios used in the Draft IRP, an additional reference case was created to reflect the lingering economic recession as shown in Figure 8-1.

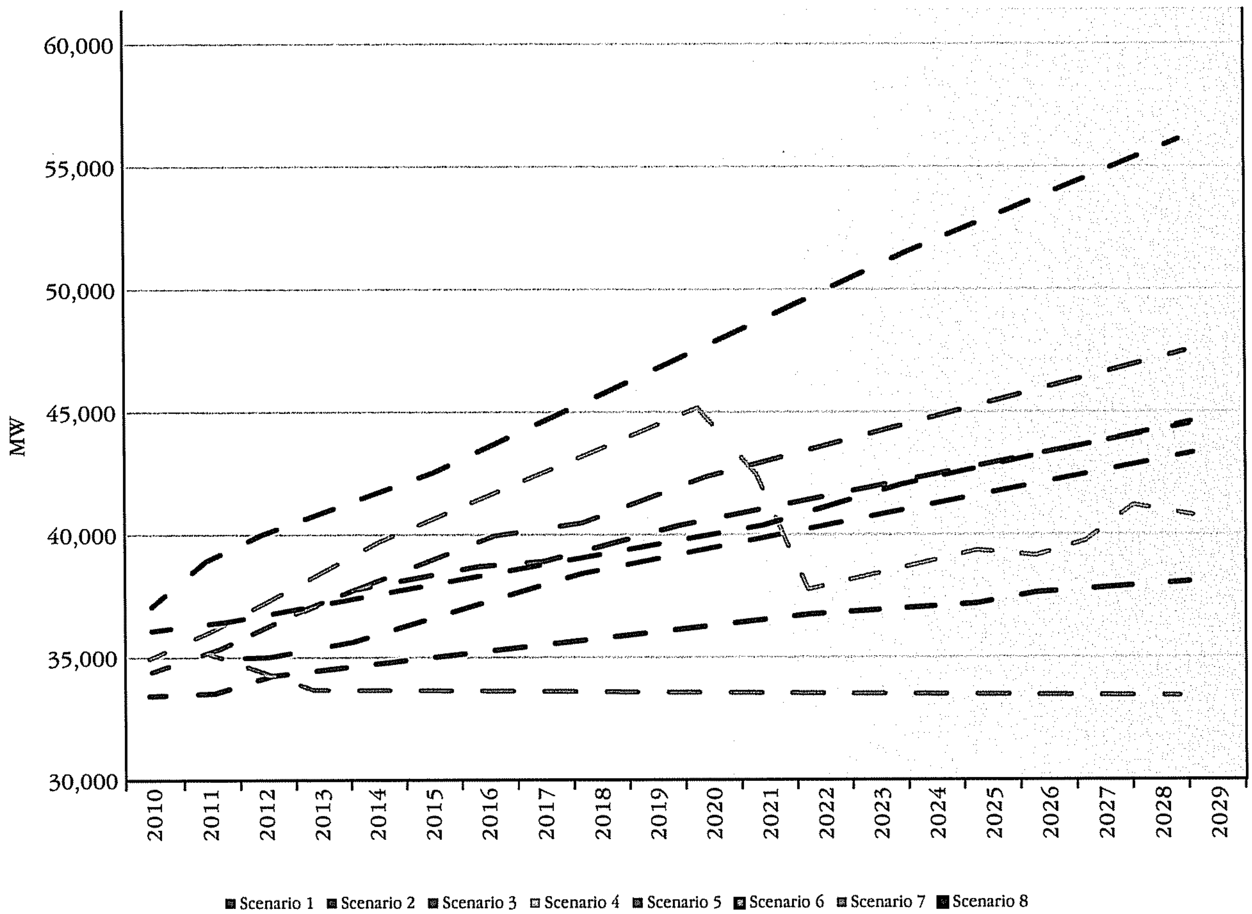


Figure 8-1 – Firm Requirements by Scenario

8.1.2 Previously Identified Sensitivities

Additional sensitivity cases were identified from work done for the Draft IRP and feedback received from stakeholders. The type of sensitivity, the purpose for analysis and the method that was incorporated into the final IRP analysis are listed in Figure 8-2.

Sensitivity Description	Basis for Selection	Method for Addressing
Evaluate increment/decrement of renewable additions for Strategy C	To identify the optimum level of renewable additions given the other assumptions already set in this strategy	• The range of renewable additions retained in the Draft IRP (along with additional increments) will be a selectable resource in the blended optimization
Evaluate alternate idled capacity values for Strategy C	To test the impact of varying idled capacity values	• The range of idled capacity retained in the Draft IRP will be evaluated with all other resources in the blended optimization
Evaluate increment/decrement of EEDR impacts for Strategy C	To identify the optimum level of EEDR given the other assumptions already set in this strategy	• The range of EEDR portfolios retained in the Draft IRP will be a selectable resource in the blended optimization
Test "gas-only" expansion in Strategy C	To evaluate the impact of gas capacity expansion on the short-term rate metric score	• "Gas-only" expansion will not allow nuclear additions • To be tested with 3,200 MW of idled capacity • All other factors will be optimized
Evaluate an aggressive EEDR portfolio that targets 50% of the capacity gap beginning in 2015	To evaluate the impact on plan cost and risk for a more aggressive portfolio of EEDR programs	• The 50% target will be based upon the capacity gap in the latest reference case (Scenario 8) with 3,200 MW of idled capacity • All other factors will be optimized
Test deferral of nuclear expansion in Strategy C until 2020	To identify the capacity additions that would be required if nuclear was not available	• Schedule of nuclear additions will be optimally selected based on the options and constraints described previously

Figure 8-2 – Sensitivity Runs Identified From Draft IRP

8.1.3 Final Study Results

The study approach in the final IRP produced 12 portfolios that resulted from a blended optimization. The boundaries (resource constraints) were defined by the planning strategies (Strategies B, C and E) retained in the Draft IRP. The 12 cases were produced by testing four possible levels of idled coal-fired capacity in each of the three representative scenarios (Scenarios 1, 3 and 8) which represent the high, medium and low load forecasts described in Section 6.1 – Development of Scenarios and Strategies. Multiple iterations were used to test all levels of idled coal-fired capacity. Optimum renewable and EEDR portfolios were selected for each assumed level of idled coal-fired capacity. Figure 8-3 summarizes the results of those cases.

	Scenario 1 Capacity Additions				Scenario 8 Capacity Additions				Scenario 3 Capacity Additions			
Idled Capacity[1]	2,400	3,200	4,000	4,700	2,400	3,200	4,000	4,700	2,400	3,200	4,000	4,700
Renewable Portfolio	2,500	2,500	2,500	2,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
EEDR Portfolio	5,074	5,074	5,074	5,074	3,627	3,627	5,074	5,074	3,627	3,627	3,627	3,627
2010	PPAs	PPAs	PPAs	PPAs								
2011												
2012	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2
2014												
2015	CTb PPAs	CTb PPAs MKT	CC CTb PPAs	CC (2) CTb PPAs	CTb	CTb	CTb	CC CTb				CC
2016	MKT	CC	CTa	CTa								
2017	CC	CTa	CT	CTa								
2018	BLN 1	BLN 1	BLN 1	BLN 1								
2019						MKT						
2020	BLN 2 PSH	BLN 2 PSH	BLN 2 PSH	BLN 2 PSH	BLN 1 PSH	BLN 1 PSH	BLN 1 PSH	BLN 1 PSH	PSH	PSH	PSH	PSH
2021												
2022	CT CTa	CC CT	CC CT	CC CT	BLN 2	BLN 2	BLN 2	BLN 2				
2023	CT	CT	CTa	CT								
2024	NUC	NUC	NUC	NUC								
2025	IGCC	MKT	IGCC	IGCC								
2026	NUC	NUC	NUC	NUC		CTa						
2027	CT	CT	IGCC	IGCC		MKT						
2028	CT	CT	CT	CTa IGCC	CTa	CT	CTa	CTa				
2029	CC	CT IGCC	CT IGCC	CTa IGCC	CT	CT	CTa	CTa				

1 – MW values based on maximum net dependable capacity

Abbreviation	Name
BLN 1	Bellefonte Nuclear Unit
CC	Combined Cycle Combustion Turbine (Natural Gas)
CT	Combustion Turbine (Natural Gas) ~800 MW
CTa	Combustion Turbine (Natural Gas) ~600 MW
CTb	Combustion Turbine Refurbishment (Natural Gas)
IGCC	Integrated Gasification Combined Cycle (Coal)
JSF CC	John Sevier Combined Cycle (Natural Gas)
MKT	Annual market purchases greater than 400 MW
NUC	AP 1000 Nuclear Unit
PPAs	Purchased Power Agreements and Acquisitions
PSH	Pumped-storage Hydro
WBN 2	Watts Bar Nuclear Unit 2

Figure 8-3 – The 12 Portfolios

Referring to the blended optimization results, the following general observations were made:

- Nuclear expansion is present in the majority of portfolios with the first unit on line between 2018 and 2020
- Expanded energy efficiency and demand response (EEDR) portfolios performed well in the optimization cases. The mid level portfolio (3,600 MW and 11,400 annual GWh reductions by 2020) was chosen in half of the cases
- Renewable generation above existing wind contracts plays a key role in future resource portfolios
- Expansion of natural gas capacity is needed, but typically occurs after 2024. Gas may serve as the most advantageous way to address any emerging supply shortage
- Preliminary financial results show that component ranges considered produced relatively robust plans with little variation in total plan costs (PVRR) within scenarios

The cost and risk metrics for the portfolios produced in the blended optimization were relatively constant across the coal-fired capacity levels, especially in Scenarios 3 and 8. This is illustrated in Figure 8-4 which compares the short-term rates ranking metrics for the portfolios organized by idled coal-fired capacity level (2,400/3,200/4,000/4,700 MW).

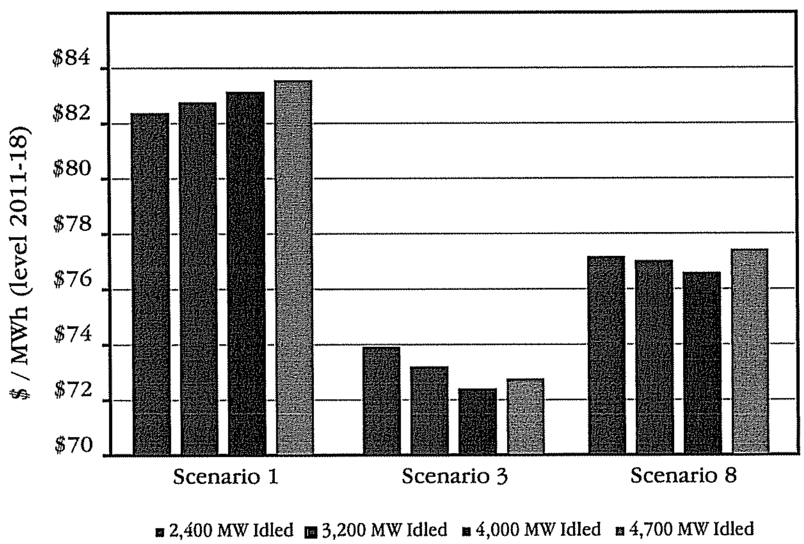


Figure 8-4 – Short-Term Rate Impacts by Scenario

This outcome was primarily driven by two characteristics. First, new unit additions are very similar in these two scenarios for all four coal-fired idling levels. Second, as the amount of idled coal-fired capacity increased from 3,200 to 4,700 MW, a larger EEDR portfolio was selected in Scenario 8. This larger portfolio had similar costs in comparison to the smaller EEDR portfolio chosen at the 2,400 MW and 3,200 MW levels. In addition, no expansion resources were selected in Scenario 3. As a result, overall PVRR for the plans was essentially unchanged.

The two metrics that measure financial risk for these resource plans were also essentially unchanged across the levels of idled coal-fired capacity except for Scenario 3. The variation seen in Scenario 3 was the result of increasing idling levels, which had an impact on the dispatch of resources in the existing system since there were no expansion resources added in that scenario.

In general, the ranking metrics show that the 12 cases produced in the blended optimization represented robust expansion solutions. The overall results were clustered closely together despite the changes in idled coal-fired capacity assumed and the variation of the key assumptions tested in the stochastic analysis. This set of portfolios represents a more focused set of possible expansion alternatives and was used to define the characteristics of the Recommended Planning Direction.

8.2 Component Identification

The Recommended Planning Direction was designed by utilizing the findings from the blended optimization to select the components that became part of the strategy. The strategy design considered the following major factors:

Stakeholder input	• Continuous dialogue with the Stakeholder Review Group • Input received from the fall 2010 Draft IRP public comment period • Quarterly public briefings conducted by TVA staff and responses to surveys
Analysis results	• Output from the resource optimization cases and associated financial modeling translated into ranking and strategic metrics
Recognition of non-quantified risks	• "No-regrets" approach • Broader considerations not fully captured in the quantitative analysis, but have some impact on the selection process

8.2.1 Idled Coal-Fired Capacity

Selection of the preferred level of idled coal-fired capacity was the next step in producing the case results in the final IRP. Cost and risk ranking metrics used in the Draft IRP were applied to select a level of idled coal-fired capacity from the options considered. Each idled capacity level was given an ordinal rank for each metric within a scenario.

The ordinal rankings for each scenario were weighted using the same formula as applied in the Draft IRP. Scores were summed for each idled coal-fired capacity level to create total ranking scores. Results are shown in Figure 8-5.

	Idled Capacity	Scenarios			Total
		Sc 1	Sc 3	Sc 8	
Weighted Ranking	2,400	1.7	3.0	2.4	7.1
	3,200	2.7	2.2	2.7	7.7
	4,000	2.5	1.7	1.7	5.9
	4,700	3.1	3.1	3.2	9.4

Figure 8-5 – Weighted Ranking Scores

Based on the ranking results, the 4,000 MW level performed the best across the three scenarios and was used as the scorecard value. This level of idled coal-fired capacity was used as a fixed assumption for further refinement of the remaining components of the Recommended Planning Direction. Model results were then reviewed to identify optimal values for the renewable resources portfolio and the level of EEDR.

8.2.2 Renewable Portfolio

In the least-cost optimized plans, results tended to favor the 1,500 MW portfolio, which represented the current wind contracts as the preferred level. However, based on stakeholder comments and feedback on the Draft IRP desiring an increased emphasis on renewable development, the Recommended Planning Direction was increased to incorporate the 2,500 MW portfolio which was used as the scorecard value. This reflects projected growth of 1,000 MW of additional renewables above existing and contracted amounts. Figure 8-6 shows a potential mix of components in this renewable portfolio.

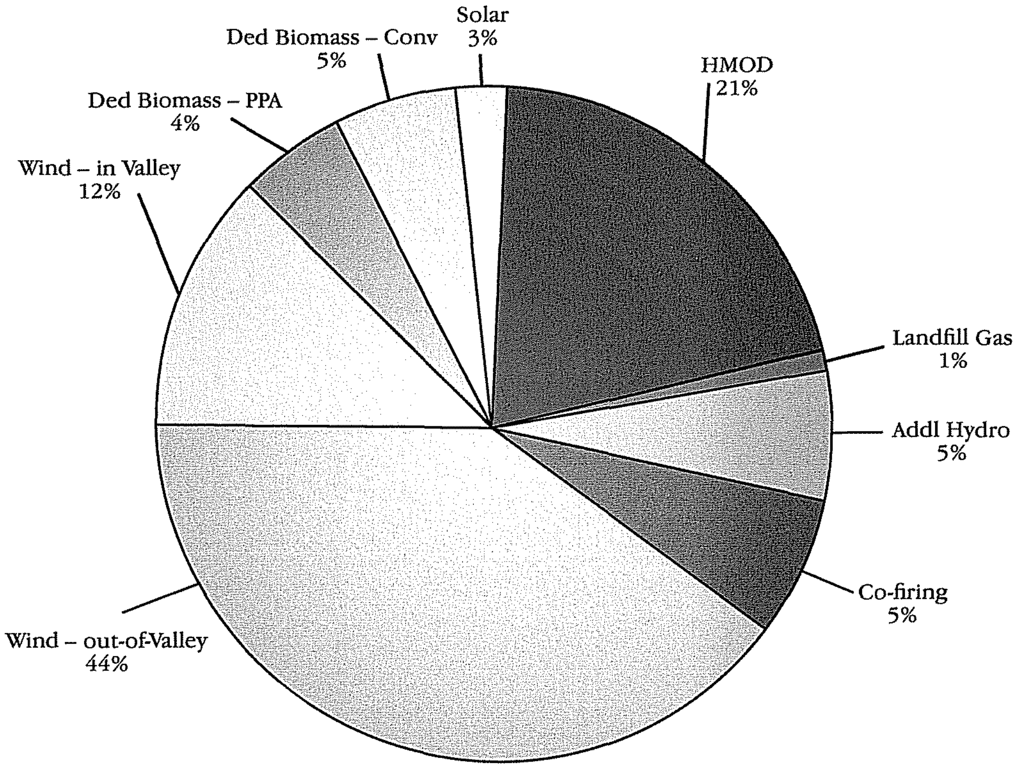


Figure 8-6 – Potential 2,500 MW Renewable Portfolio

Prior to making this decision, the cost premium to increase to the 2,500 MW portfolio was calculated. It was determined to be relatively small (typically less than 1 percent of total plan cost). Not all of this cost change was directly attributable to the renewable portfolio itself because of other changes in the resource plan. This premium was deemed acceptable given TVA's objectives to increase reliance on cleaner and more environmentally responsible energy sources.

8.2.3 EEDR Portfolio

The modeling results were evenly split in selecting either the mid level EEDR portfolio (3,600 MW by 2020) or the larger portfolio (5,100 MW by 2020). For reference, the mid level portfolio was part of Strategy C, and the larger portfolio was included in Strategy E in the Draft IRP.

Given the uncertainty about the pace of customer participation and the implementation challenge for TVA associated with the larger portfolio, the mid level EEDR portfolio was used as the scorecard value. This selection also recognized there are similar non-quantified risks associated with implementation of this mid level portfolio. Those risks were deemed to be sufficiently manageable to include the portfolio in the Recommended Planning Direction.

For a more complete discussion of the non-quantified risks that were part of TVA's assessment of the planning strategies, see Chapter 6 – Resource Plan Development and Analysis.

8.3 Recommended Planning Direction Development

8.3.1 Key Characteristics

After the key components of idled coal-fired capacity, EEDR and renewables were determined, the key characteristics of the strategies following the blended optimization were observed. These observations are shown in Figure 8-7.

Component	Observations
Nuclear additions	Nuclear expansion is present in the majority of portfolios. Up to three[1] units are added between 2013 and 2029
Coal additions	New coal capacity is only selected after 2025 in scenarios with dramatic load growth
Natural gas additions	Expansion of natural gas is needed, but typically occurs after 2024 with simple-cycle combustion turbines. The dramatic load growth scenario is an exception as combined cycles and combustion turbines are chosen as early as 2015. Additional units may be required for reliability and/or grid stability
Renewable additions	Model results tend to favor the current wind contracts (1,500 MW) as the least cost plan. The renewable portfolio that delivers 2,500 MW by 2029 is selected in the dramatic load growth scenario
EEDR	Results evenly split in selecting either the 3,600 MW by 2020 portfolio and the 5,000 MW by 2020 portfolio

1 – Included in number of nuclear units is TVA Board of Directors' approved project Watts Bar Unit 2

Figure 8-7 – Observations Developed from Preliminary Results

The remaining components of the Recommended Planning Direction were selected with consideration of these outcomes. Figure 8-8 is a tabular summary of the Recommended Planning Direction.

Component	Guideline MW Range	Window of Time	Recommendations
EEDR	3,600-5,100 (11,400-14,400 GWh)	By 2020[1]	Expand contribution of EEDR in the portfolio
Renewable additions	1,500-2,500[2]	By 2020[1]	Pursue cost-effective renewable energy
Coal-fired capacity idled	2,400-4,700[3]	By 2017	Consider increasing amount of coal capacity idled
Energy storage	850[4]	2020-2024	Add pumped-storage capacity
Nuclear additions	1,150-5,900[5]	2013-2029	Increase contribution of nuclear generation
Coal additions	0-900[6]	2025-2029	Preserve option of generation with carbon capture
Natural gas additions	900-9,300[7]	2012-2029	Utilize natural gas as an intermediate supply source

1 – This range includes EEDR savings achieved through 2020. The 2020 range for EEDR and renewable energy does not preclude further investment in these resources during the following decade

2 – TVA's existing wind contracts that total more than 1,600 MW are included in this range. Values are nameplate capacity. Net dependable capacity would be lower

3 – TVA has previously announced plans to idle 1,000 MW of coal-fired capacity, which is included in this range. MW values based on maximum net dependable capacity

4 – This is the expected size of a new pumped-storage hydro facility

5 – The completion of Watts Bar Unit 2 represents the lower end of this range

6 – Up to 900 MW of new coal-fired capacity is recommended between 2025 and 2029

7 – The completion of John Sevier combined cycle plant represents the lower end of this range

Figure 8-8 – Recommended Planning Direction

The above figure contains seven components that comprise the strategy and shows a range of the amount for each component as well as the timing of when these components would be added to the system.

8.3.2 Recommended Planning Direction Illustrative Portfolios

After the Recommended Planning Direction was defined, it was evaluated to determine if it represented an improvement over the strategies evaluated in the Draft IRP. A group of portfolios was developed and scored.

To produce the portfolios, the Recommended Planning Direction was tested in each of the eight scenarios. These portfolios were based on scorecard values for the key components of the Recommended Planning Direction (idled coal-fired capacity, EEDR and renewables) with optimized additions of the other resources that made up the capacity plans.

The resultant portfolios are illustrative in nature and based on the particular set of assumptions contained in each of the scenarios. Figure 8-9 is a tabular summary of the illustrative portfolios for the Recommended Planning Direction and shows the resource plans that result in each of the eight scenarios.

Year	Capacity Additions by Scenario									
	EEDR	Renewables	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
2010	300 MW	300 MW	PPAs							
2011										
2012			JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013			WBN 2 PPAs	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2	WBN 2
2014			CT			CTb PPAs				
2015			CC CTb CT PPAs			CC PPAs	CTb PPAs		CTb PPAs	CTb PPAs
2016			CT			CT	MKT		MKT	MKT
2017			MKT			MKT			MKT	
2018			BLN 1	BLN 1		BLN 1			BLN 1	
2019			MKT			MKT	MKT		MKT	MKT
2020	3,600 MW	2,500 MW	BLN 2 PSH	BLN 2 PSH	PSH	BLN 2 PSH	BLN 1 PSH	PSH	BLN 2 PSH	BLN 1 PSH
2021			CC							
2022			CC MKT				BLN 2			BLN 2
2023			CT MKT						CTa	
2024			NUC							
2025			IGCC MKT						CT	
2026			NUC						MKT	CT
2027			CT				MKT		CT	MKT
2028			CT				CT		MKT	CT
2029	4,600 MW	2,600 MW	CT IGCC	CT			CT		CT	CT

*Illustrative portfolios assume 4,000 MW of idled coal-fired capacity by 2015

Additions			
Natural Gas		Pumped Hydro	
Coal		Renewables	
Nuclear		EEDR	
Purchased Power			

Figure 8-9 – Illustrative Portfolios for the Recommended Planning Direction

After reviewing the resource plans in Figure 8-9, the following observations can be made about near-term and long-term additions:

- Near-term additions (0-5 years) were generally consistent across the scenarios, reflecting the addition of approved projects by the TVA Board of Directors, which include additions at John Sevier and Watts Bar. Resource additions in this time frame also included new natural gas plants and purchased power arrangements, depending on load growth
- Long-term additions (5-20 years) were somewhat more flexible. Nuclear capacity was a major component of the capacity plans in this period, with the first nuclear unit typically added between 2018 and 2020. Expansion of natural gas capacity often occurred after 2024

8.3.3 Recommended Planning Direction Validation

The Recommended Planning Direction was scored using the same ranking and strategic metrics utilized in the Draft IRP. The scorecard results of the Recommended Planning Direction were compared to the scorecard results of the strategies retained from the Draft IRP. Figure 8-10 is a fully populated scorecard for the Recommended Planning Direction, and Figures 8-11 and 8-12, respectively, show scorecards from the Draft IRP for Strategy C and Strategy E.

	Ranking Metrics – Financial Impact					Strategic Metrics – Environmental Stewardship			Strategic Metrics – Economic Impact	
Scenarios	PVRR	Short-Term Rate Impact	PVRR Risk/ Benefit	PVRR Risk	Total Plan Score	CO_2 Foot-print	Water	Waste	Total Em-ploy-ment	Growth in Per-sonal Income
1	99.00	95.13	100.00	99.53	98.36	◕	◕	◕	0.9%	0.7%
2	100.00	95.58	99.40	95.30	97.85	◕	◑	◑		
3	100.00	100.00	99.81	89.37	97.56	◕	◕	◕		
4	100.00	97.40	100.00	95.37	98.36	●	◕	◕		
5	100.00	96.43	100.00	100.00	99.19	◕	◕	◑		
6	100.00	100.00	100.00	86.69	96.97	◕	◕	◕	0.2%	0.1%
7	100.00	97.24	100.00	97.03	98.70	◕	◕	◕		
8	99.84	96.66	98.35	97.93	98.50	◕	◕	◑		
				Total Ranking Metric Score	785.49					

Legend	
●	Better
◕	↑
◑	
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Figure 8-10 – Recommended Planning Direction

	Ranking Metrics: Financial Impact					Strategic Metrics: Environmental Stewardship			Strategic Metrics: Economic Impact	
Scenarios	PVRR	Short-Term Rate Impact	PVRR Risk/ Benefit	PVRR Risk	Total Plan Score	CO_2 Foot-print	Water	Waste	Total Em-ploy-ment	Growth in Per-sonal Income
1	99.22	94.09	97.68	100.00	98.04	◑	◑	◑	0.9%	0.6%
2	96.35	100.00	96.46	95.85	97.08	◑	◕	◕		
3	95.56	94.68	100.00	100.00	96.91	◑	◑	◑		
4	97.39	98.37	98.19	100.00	98.30	◕	◑	◑		
5	98.90	100.00	97.49	99.17	99.04	◑	◑	◕		
6	95.08	94.41	97.83	93.22	94.82	◑	◑	◑	0.2%	0.1%
7	98.88	98.94	99.45	100.00	99.22	◑	◑	◑		
8	99.56	99.63	99.03	99.31	99.45	◑	◑	◕		
				Total Ranking Metric Score	782.86					

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	Better
●	Better
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Figure 8-11 – Planning Strategy C – Updated Scorecard

	Ranking Metrics: Financial Impact					Strategic Metrics: Environmental Stewardship			Strategic Metrics: Economic Impact	
Scenarios	PVRR	Short-Term Rate Impact	PVRR Risk/ Benefit	PVRR Risk	Total Plan Score	CO_2 Foot-print	Water	Waste	Total Em-ploy-ment	Growth in Per-sonal Income
1	100.00	100.00	96.78	95.46	98.57	●	●	●	0.8%	0.6%
2	97.74	98.20	99.96	98.54	98.30	●	●	●		
3	94.67	93.55	95.91	97.73	95.26	●	●	●		
4	96.83	100.00	93.42	89.57	95.48	◑	●	●		
5	98.72	99.50	96.33	98.64	98.59	●	●	●		
6	95.62	93.91	99.65	100.00	96.72	●	●	●	0.3%	0.2%
7	98.56	100.00	98.42	98.96	98.96	●	●	●		
8	100.00	100.00	100.00	100.00	100.00	●	●	●		
				Total Ranking Metric Score	781.88					

Legend	
	Better
●	Better
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Figure 8-12 – Planning Strategy E – Updated Scorecard

Comparing the Recommended Planning Direction to the top two strategies from the Draft IRP (Strategy C and Strategy E) shows that the Recommended Planning Direction represents the most favorable blending of portfolio components. The performance of the Recommended Planning Direction across all scenarios implies that it is a more robust approach with a lower likelihood of regret. The following are additional observations based on the scorecard results:

- The Recommended Planning Direction was the top performer on total plan cost (PVRR) in six of the eight scenarios tested
- The Recommended Planning Direction was the top performer on the risk/benefit ratio metric in five of the eight scenarios
- The strategic metrics for the Recommended Planning Direction were improved from metrics for Strategy C (the top-ranked strategy from the Draft IRP), but were not as good as the strategic metrics for Strategy E
- The economic impact metrics for the Recommended Planning Direction were similar to the metrics for the strategies retained from the Draft IRP, indicating there was no significant difference among the strategies in terms of macroeconomic impacts

The Recommended Planning Direction provided a more effective balance between plan cost and financial risk, as shown in Figure 8-13. The graph presents a cost versus risk curve, and the Recommended Planning Direction provided the lowest combination of plan cost (PVRR) and financial risk of any of the strategies that were considered in this IRP.

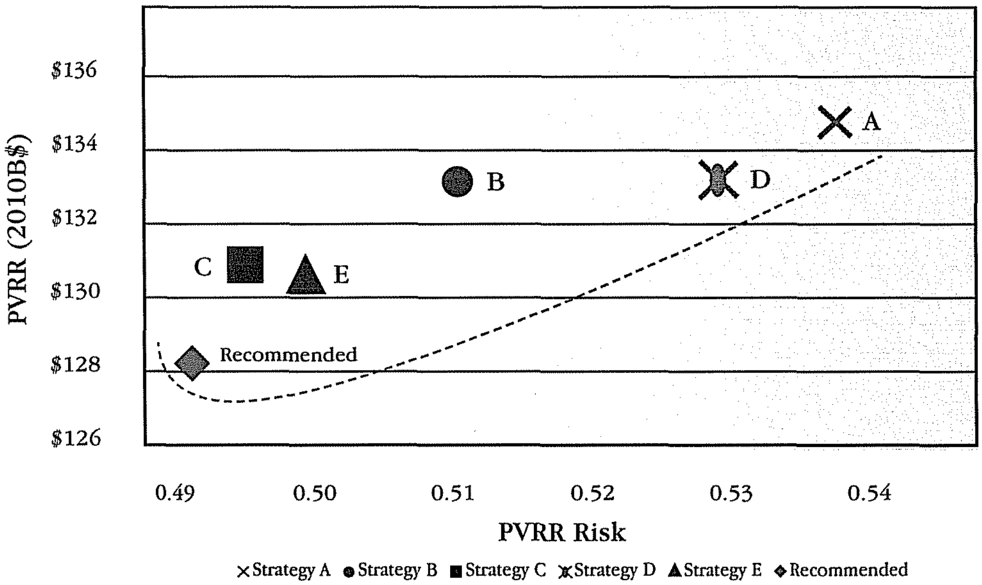


Figure 8-13 – Plan Costs vs. Financial Risk

Figure 8-14, a risk trade-off graph that compares financial risk versus the risk/benefit ratio, reinforces the conclusion drawn from Figure 8-13. This shows that improved risk performance comes at a higher overall plan cost.

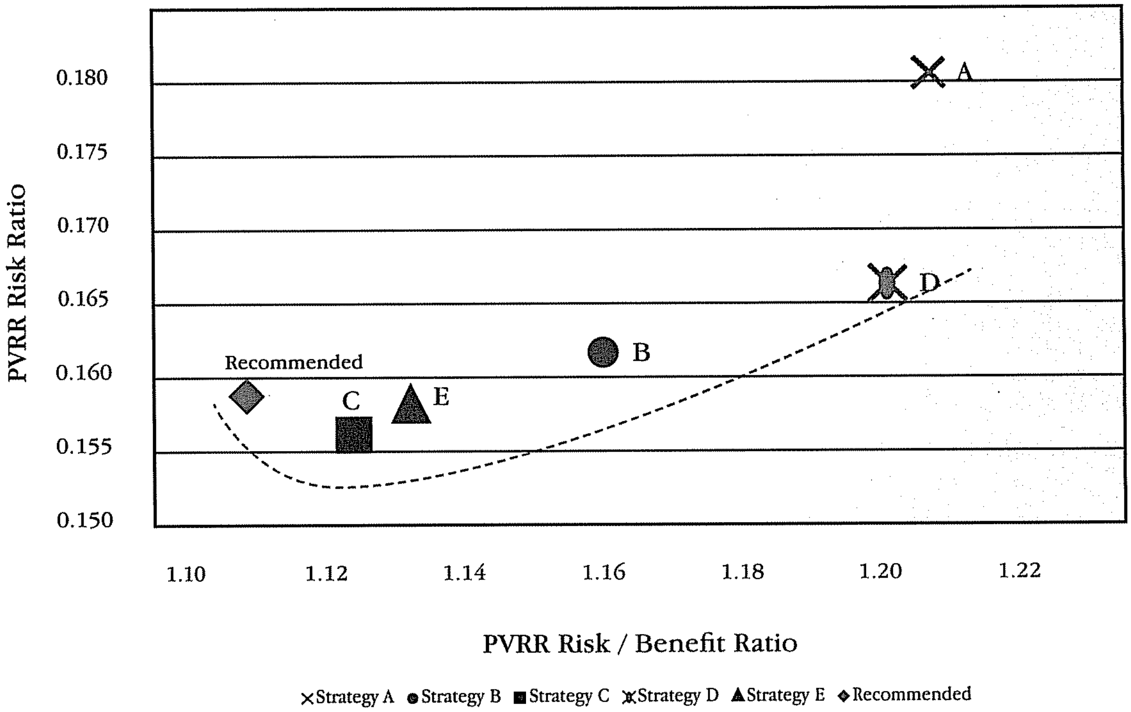


Figure 8-14 – Comparison of Financial Risks of Strategies

The uncertainty range in PVRR across the scenarios was another measure of performance used to assess the Recommended Planning Direction. Figure 8-15 is a tornado diagram of the variation in total plan cost (PVRR) from the stochastic analysis of the strategies in each of the eight scenarios. The width of the bars indicates the variation and uncertainty in plan cost. This figure shows that in most scenarios the Recommended Planning Direction (R) had the smallest range of cost uncertainty and that the expected value of the total plan cost was lower compared to the other strategies (C or E).

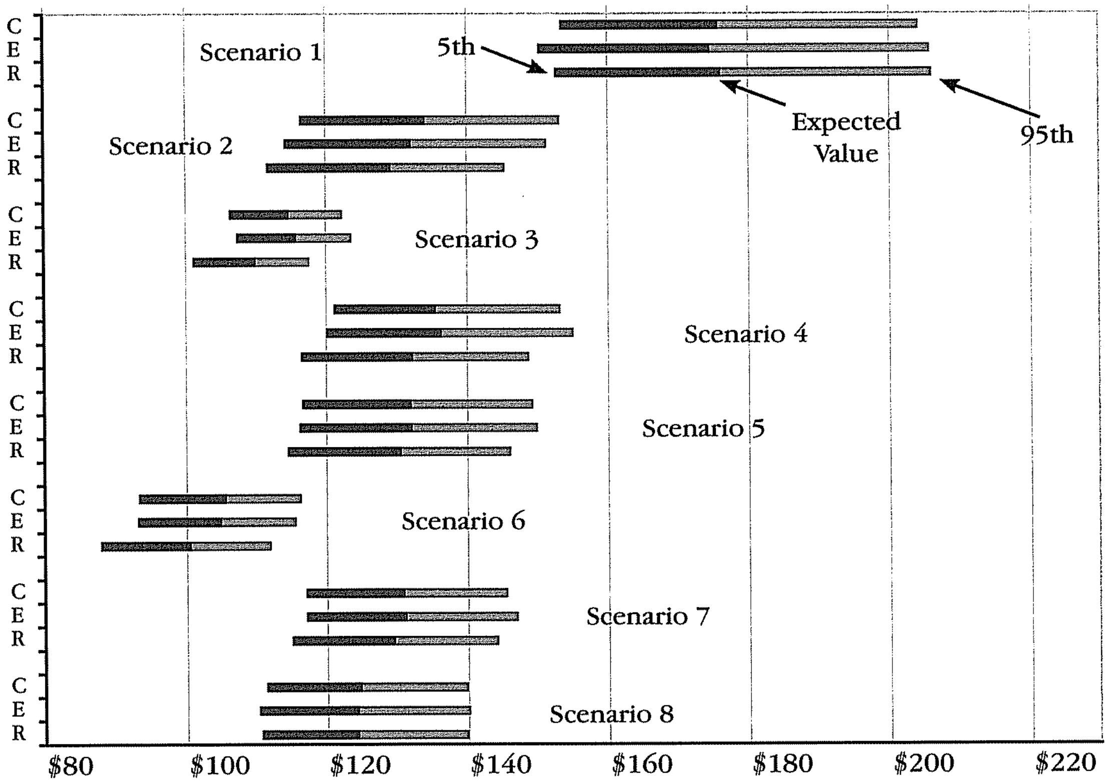


Figure 8-15 – PVRR (2010 $B)

In addition to financial trade-offs, the Recommended Planning Direction also provided the best balance of plan cost and environmental footprint, represented by the graph of plan cost versus CO_2 tons shown in Figure 8-16.

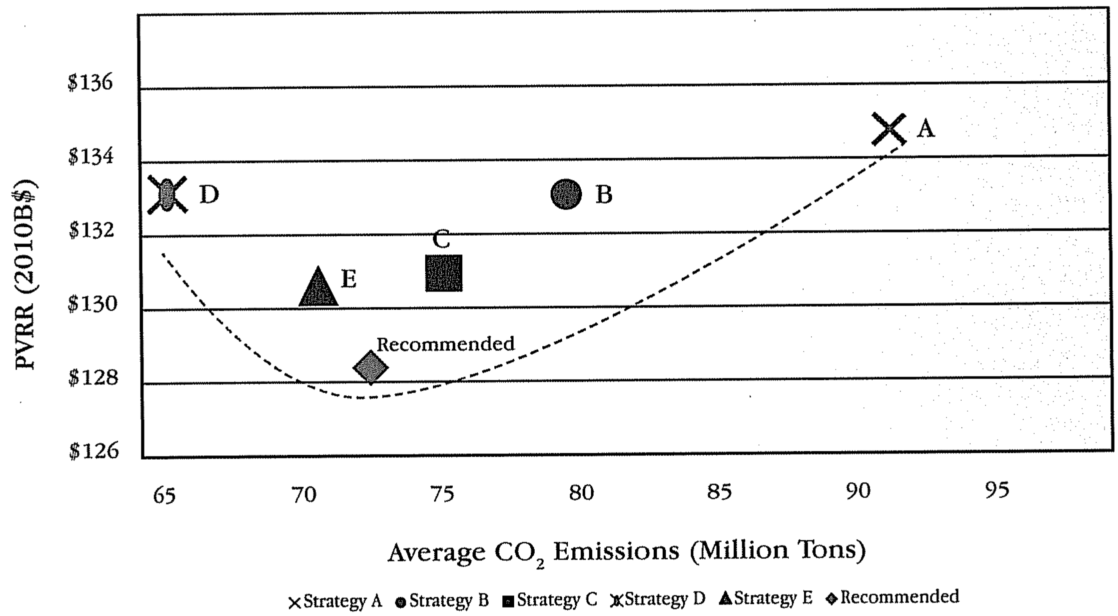


Figure 8-16 – Plan Costs vs. Annual CO_2 Emissions

8.3.4 Other Considerations

The modeling results represented by the ranking and strategic metrics, along with other financial and risk assessments discussed in the preceding section, provided strong support for the Recommended Planning Direction. However, as indicated in Section 7.2.4 – Other Strategic Considerations, the analytics are not the only considerations that were factored into the selection of TVA's Recommended Planning Direction. Certain non-quantified risk concerns, also known as "no-regrets considerations," were included, either directly or indirectly, when making the selection. Figure 8-17 shows the key items of the "no-regrets considerations."

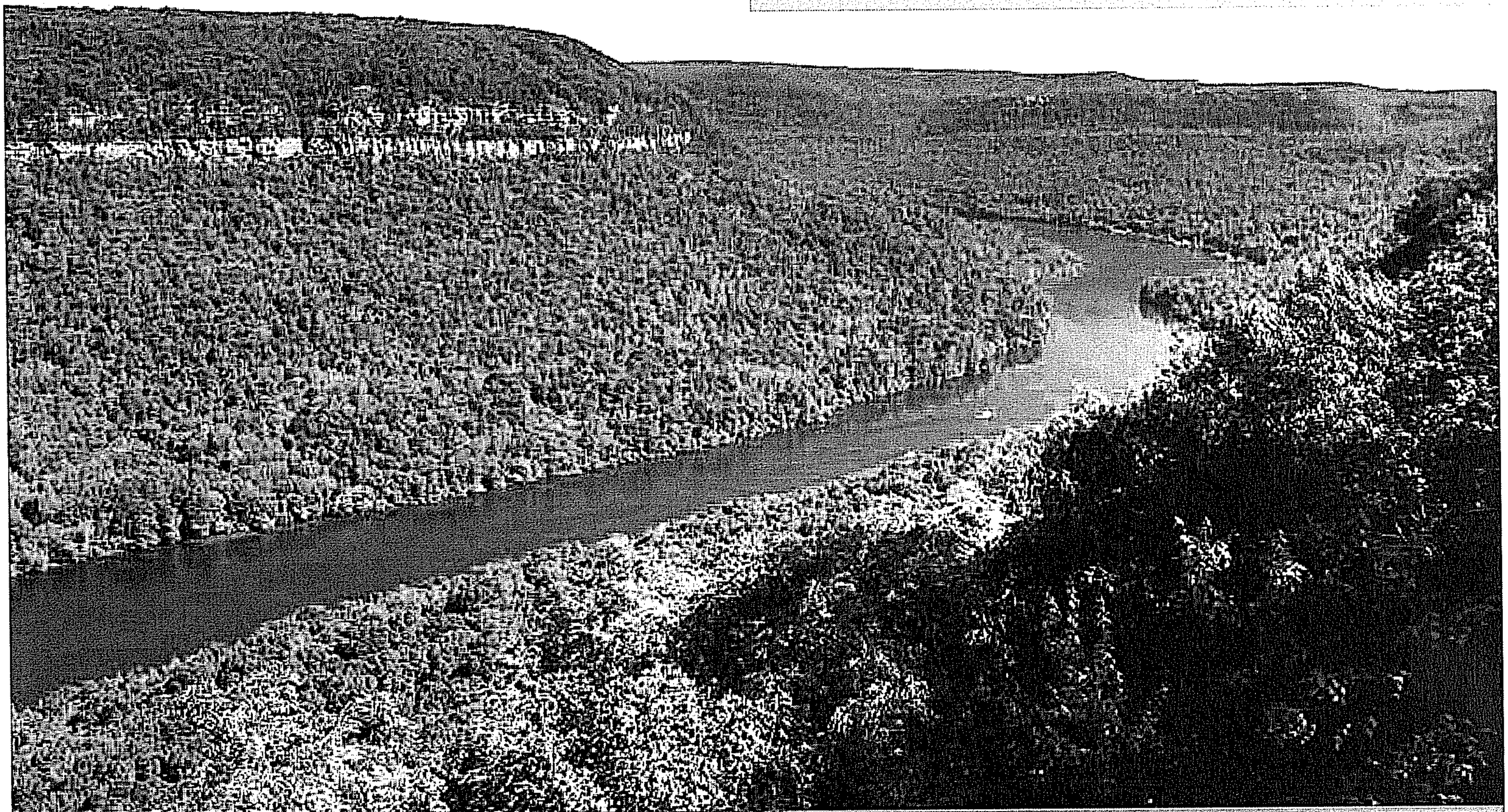
Other Risk Considerations	Potential Implications	Potential Early Warning Signs
Establishing a successful partnership with distributor group to administer EEDR programs and deliver forecasted reductions	• Planning strategies with higher EEDR targets will have a greater exposure to this risk	• Delays in establishing formal agreement with distributors by end of FY 2012
The ability of EEDR programs to stimulate customer participation and deliver forecasted reductions	• Planning strategies with higher EEDR targets will have a greater exposure to this risk	• Measurement and verification data of actual reductions is significantly below forecast
The ability to achieve schedule targets for licensing/permitting, developing and constructing large baseload generation	• Risks of meeting schedule targets will likely increase as the number and complexity of construction projects increase • Projects with more extensive permitting requirements may have greater exposure to schedule risk	• Critical internal resources for permitting, design, and construction are not maintained for upcoming projects • Dramatic changes in licensing/ permitting requirements
The timely build-out of transmission and distribution (smart grid) infrastructure to support future resources	• Risks will likely increase as the amount of construction required increases; particularly if that construction is undertaken by entities other than TVA	• Diminished availability of transmission design and construction resources • Limited smart grid capability added to distribution system by 2015
The ability to maintain appropriate operational flexibility after significant changes in resource mix	• Risks of limiting operational flexibility increase as the quantity of baseload, dispatchable, and non-dispatchable resources change	• Prolonged increases in system load factor • Emergence of barriers that delay addition of energy storage

Figure 8-17 – Other Risk Considerations

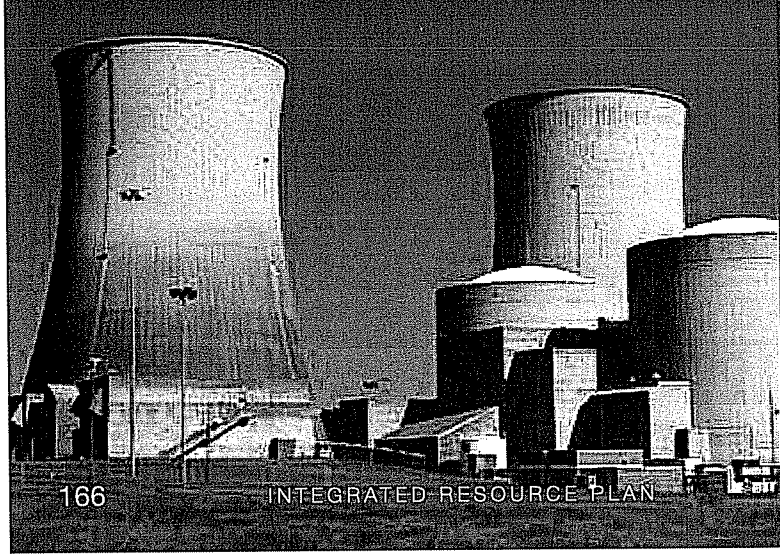
The Recommended Planning Direction provides the most balanced approach to mitigating the risk associated with these non-quantified factors while providing the best performance in key metrics.

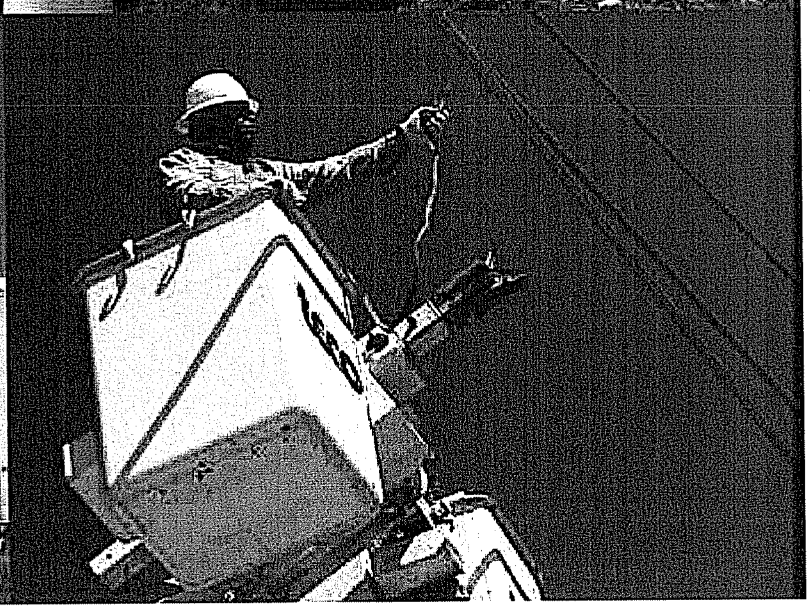
8.4 Conclusion

Based on the results of the analysis conducted in the Draft and final IRP, as well as the consideration of non-quantified risk factors, the Recommended Planning Direction positions TVA with the best balance of flexibility and "no-regrets" risk mitigation. A discussion of next steps and recommendations for implementation of this strategy is discussed in Chapter 9 – Next Steps.

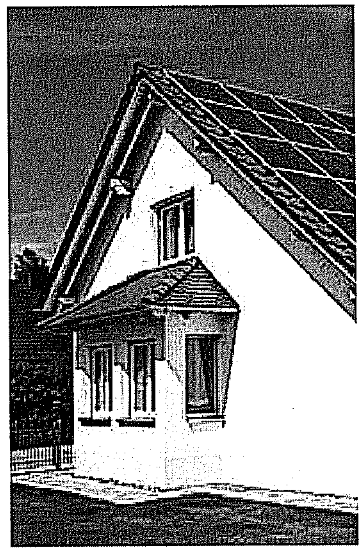


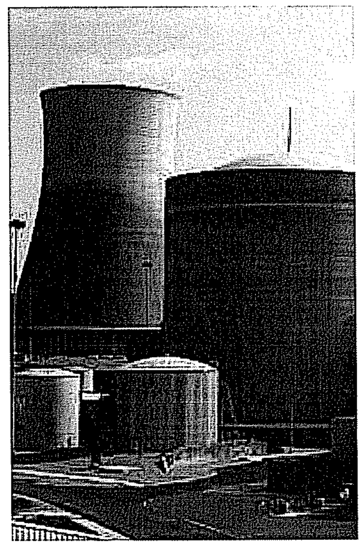
Renewable, sustainable, environmentally-friendly initiatives, as well as consumer education regarding energy efficiency in the home and at work are all key components of TVA's future strategy for the Tennessee Valley.





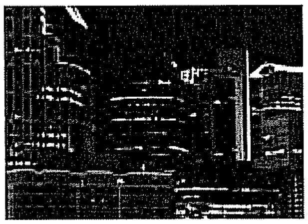
Next Steps





Implementing this strategy will help TVA meet its renewed vision–to be one of the nation's leading providers of low-cost and cleaner energy by 2020.

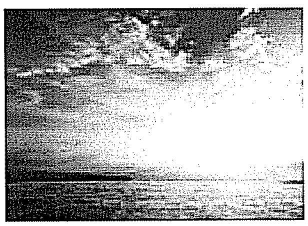
Elements of Vision 2020



Low Rates

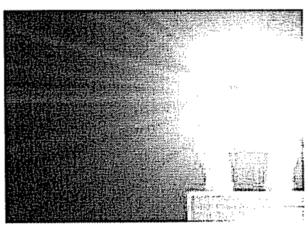
High Reliability

Responsibility



Cleaner Air

More Nuclear Generation



Greater Energy Efficiency

9 Next Steps

After two years of extensive analysis and the issuance of the Draft IRP, the final IRP has been completed. Another key piece of the puzzle is defining the next steps that follow this IRP's completion. For that reason, it is important to remember that this IRP is meant to serve as a roadmap for making future asset decisions and not meant to define specific decisions.

Approval of this IRP provides an updated strategic direction that will help TVA fulfill its renewed vision and set the direction for many decisions that will be proposed in the future. This chapter defines some of the key areas that need additional work or investigation to help determine TVA's "next steps" in these specific areas.

9.1 Path Forward

TVA formulated this IRP to help prepare for a wide range of future conditions and ensure a sustainable future for the Tennessee Valley region. This IRP will serve as a guide to achieve TVA's renewed vision – to become one of the nation's leading providers of low-cost and cleaner energy by 2020. TVA takes great pride in the reliable service it provides to its customers. Transmission reliability will remain a key focus of all future operations. TVA will also strive to maintain the proper generation mix in order to ensure reliable and flexible power system operation.

Furthermore, TVA remains committed to reducing air emissions from its power generation facilities. Emissions reduction will help TVA plan for and promote a sustainable future. Coal-fired plant idling and the addition of scrubbers and other emissions control equipment are essential for TVA to provide cleaner energy.

The reputation of delivering reliable, competitively priced power makes the Tennessee Valley region an attractive place to start or expand a business. Therefore, TVA will continue to support and encourage economic development in the region. TVA offers an array of services that include capital investment loans for new or growing businesses, site-selection assistance and other business support services. These services help attract companies to the region and provide more jobs to aid in economic stability of the region, which is especially important with the current sluggish economy.

TVA President and CEO Tom Kilgore stated, "TVA's basic missions have not changed, but the times have changed and requirements are changing for the energy industry." The analysis performed within this IRP will help TVA prepare for future uncertainties and properly position itself to effectively continue its mission to serve the people of the Tennessee Valley.

9.2 Application

While this strategy will help guide TVA in making important decisions in the years to come, this IRP does not dictate a specific series of actions. It is important to understand what analysis was considered to be within the scope of this IRP and what areas may require more analysis. Figure 9-1 lists what was considered in-scope versus outside-of-scope in this IRP.

This IRP Does	This IRP Does Not
Articulate a 20-year planning direction	• Finalize specific asset decisions • Serve as a substitute for the "fine-tuning" of the annual planning and budgeting processes
Present recommended strategy alternatives	• Narrow the breadth of NEPA coverage established in the Draft IRP and the associated EIS • Does not discard analyses done for alternative strategies
Describe guideline ranges for key components of the Recommended Planning Direction (i.e., EEDR, idling of coal-fired units, etc.)	• Make specific commitments for key components of the Recommended Planning Direction
Present illustrative portfolio(s) that show potential asset additions by year	• Commit to a specific 20-year capacity addition schedule
Highlight key asset additions by showing a specific value *within the guideline range in the illustrative portfolio*	• Imply that any asset addition or in-service date shown in the illustrative portfolio represents a formal decision or is not subject to change
Discuss other strategic considerations and non-quantified risk considerations	• Quantify all risks in the analysis or imply all decision criteria are within the IRP scope
Commit to beginning the next IRP by 2015	• Expect to provide NEPA coverage for the same duration as EV2020 • Limit TVA's ability to continue to do analysis and amend this IRP in the future

Figure 9-1 – Scope of the IRP

9.3 Areas That Require Further Work

By closely evaluating the areas that require more analysis, a number of recommendations have been identified and summarized on the next page. This list is not designed to be exhaustive but does provide insight into additional work that TVA will consider undertaking.

Issue	Recommendation
Idling coal-fired units	• Perform detailed optimization analyses to determine both the optimum level of idling and the best units for idling after accounting for risks, uncertainty and all known costs
Renewables	• Analyze renewable technologies and business models and monitor market trends for strategic options to develop cost-effective renewable resources
Nuclear power	• Complete project specific evaluation of B&W technology at Bellefonte site and refine timing • Continue to study development of small modular reactors as part of the continuing effort to advance carbon-free, baseload power generation alternatives
EEDR	• Proactively pursue the Southeast leadership goal, monitor results and evaluate programs
Gas-fired supply	• Analyze gas-fired supply opportunities to cost effectively fill short lead time capacity gaps
Pumped-storage	• Study more detailed project economics of and justification for additional pumped-storage with a goal of making a recommendation on how to proceed
Stakeholder involvement	• Continue to solicit input from external stakeholders and incorporate that input into future IRP planning and decision making processes
Next IRP	• TVA has committed to begin the next IRP effort by 2015

Figure 9-2 – Areas That Require Further Work

9.4 Conclusion

Fifteen years separated the completion of this IRP and the 1995 IRP, EV2020. Comments TVA received from SRG members and the public recommend that TVA needs to regularly update its IRP. Frequently updating this IRP would enhance TVA's ability to effectively respond to future developments. For that reason, TVA is committed to begin the next IRP effort by 2015.

TVA's IRP has produced an energy resource strategy that will help TVA meet the Tennessee Valley region's energy demands in the future in a sustainable manner. Implementing this strategy will also help TVA meet its renewed vision – to be one of the nation's leading providers of low-cost and cleaner energy by 2020. More specifically, this IRP will help TVA lead the nation in improved air quality and increased nuclear production, and lead the Southeast in increased energy efficiency.

This concludes the 2011 TVA Integrated Resource Plan,
TVA's Environmental and Energy Future.

Appendix A – Method for Computing Environmental Impact Metrics

Purpose

The IRP used a multi-component scorecard analysis of ranking and strategic metrics for evaluating the impacts of the planning strategies. In addition to the metrics used to establish the rank order of the planning strategies (cost and risk) with emissions costs imbedded, TVA developed strategic metrics, such as the environmental impact metric, to more clearly depict environmental stewardship attributes.

Process

In developing the criteria for the environmental impact metric, TVA staff wanted to create a metric representative of the trade-offs between energy resources rather than identifying a single resource with the "best" environmental performance. The final evaluation criteria relied on some surrogate measures as a proxy for environmental impacts, but when used comparatively with the other attributes, they provided a reasonable and balanced method for evaluating planning strategies. By considering air, water and waste in the IRP scorecard, coupled with the broader qualitative discussion of anticipated environmental impacts in the EIS, a robust comparison of the environmental footprint of the planning strategies better informed the selection of the Recommended Planning Direction.

Method

Outlined below is the methodology that was used for the environmental impact metric, by attribute, including a revised scoring of the strategies that were considered in the Draft IRP, excluding Strategies A and D, and inclusion of Strategy R – Recommended Planning Direction.

Air Impact Metric and Ranking

Model results provided data on the production of four emissions: CO_2, SO_2, NO_X and Hg by generation source (e.g., coal and lignite). The suite of emissions selected to evaluate the air impacts of the IRP strategies were meant to represent a range of emissions primarily associated with fossil-fueled power generation. It was suspected that evaluating the strategies on the basis of all four emissions would give the same results (i.e., declining emissions trends) as just using CO_2 alone, but emission trend plots were developed to confirm this assumption. Emission trends were plotted against averaged, historic TVA generation data from 2007 to 2009 for coal and combustion turbines. The most recent three years were used to provide a better representation of average air emissions, as 2009 was a historically low year for air emissions due partly to the economic recession and decreased electricity demands. Historic mercury emissions for lignite sources were unavailable, so projected data for 2010 was used and added to the other totals. Figure A-1 provides a summary of the baseline emissions that data emissions trends were plotted against.

	SO_2 (tons)	NO_x (tons)	CO_2 (tons)	Hg (lbs)
TVA Coal	302,818	140,528	94,879,125	2,597
TVA CTs	27	359	1,954,211	N/A
Lignite	817	1,235	2,092,848	55
Totals	**303,622**	**142,122**	**98,926,184**	**2,652**

Figure A-1 – Summary of 2007-2009 Average Emissions Data

Again using model results by generation sources for each of the cases, excluding cases associated with Strategies A and D, CO_2 emissions data from all emission sources were summed for selected spot years (five-year increments) 2010, 2015, 2020, 2025 and 2028. Then for each of these years, the CO_2 emissions for each strategy, excluding Strategies A and D, were summed across all eight scenarios, which gives a value for the total CO_2 emissions associated with each strategy. These totals were divided by eight to provide a representative average value for each spot year that could be compared to the 2007–2009 averaged historical baseline data. These data were plotted to demonstrate how CO_2 emissions vary over time (Figure A-2).

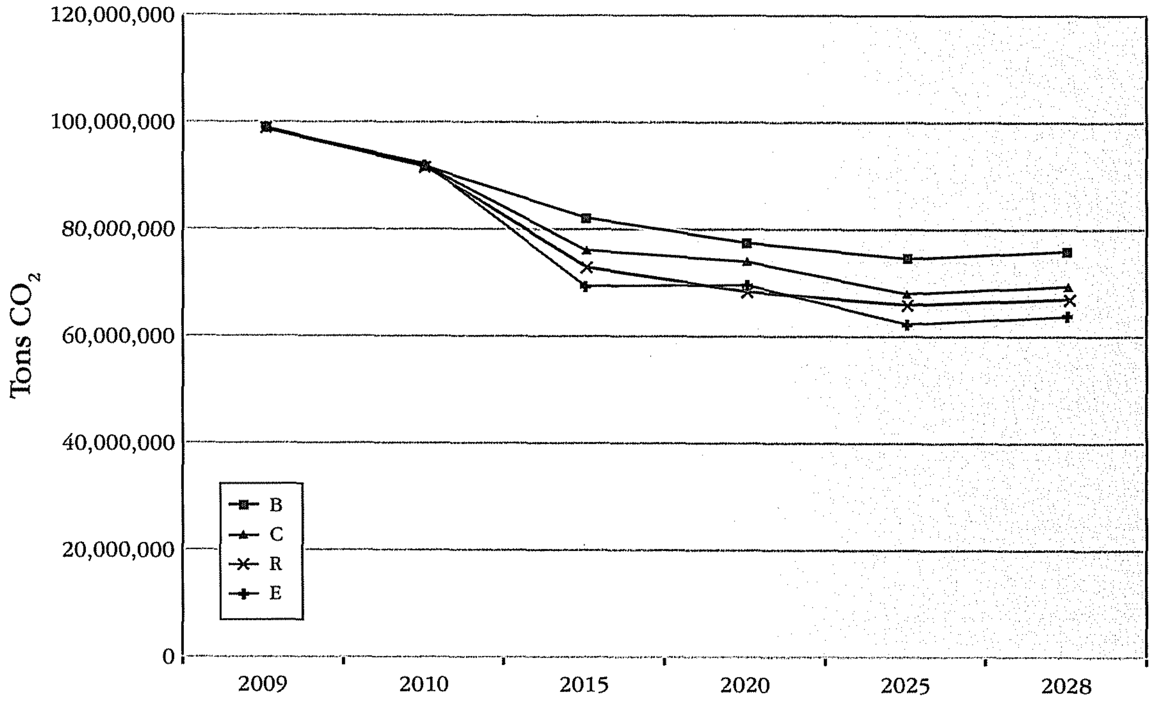


Figure A-2 – Tons CO_2 by Strategy

Similar calculations were also done for SO_2, NO_x and Hg as shown in Figures A-3, A-4 and A-5.

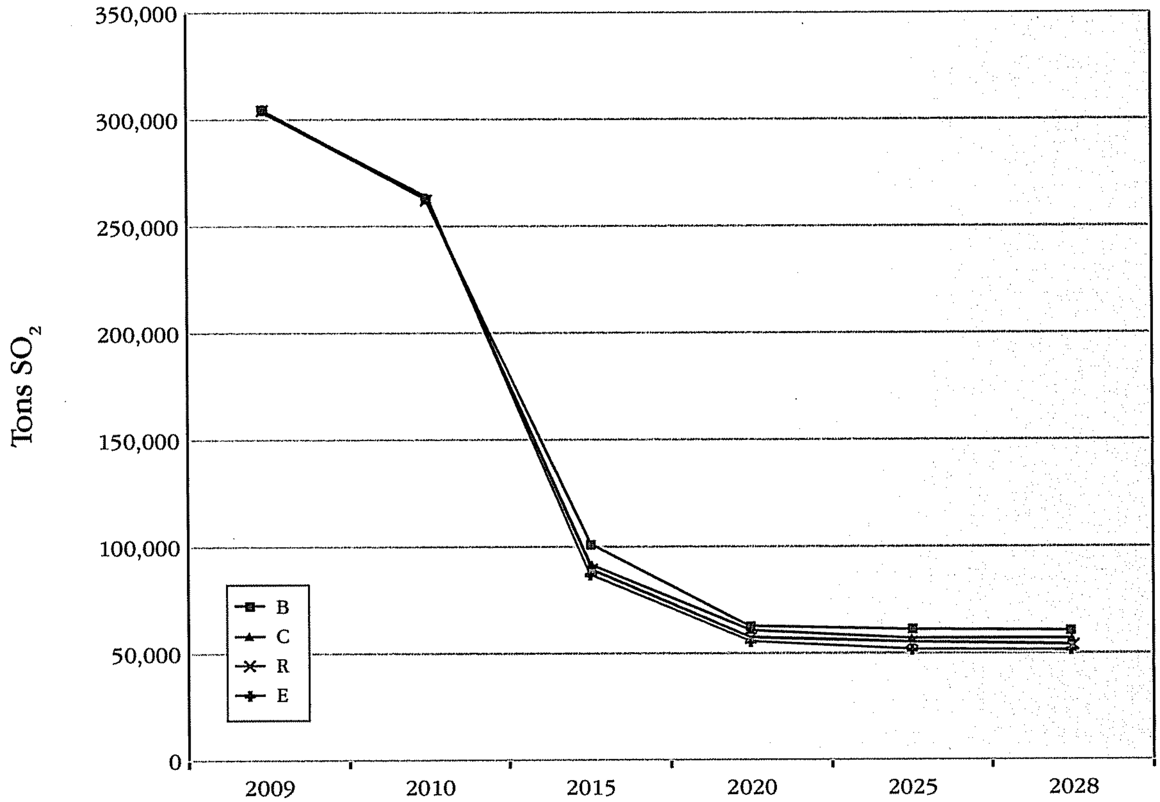


Figure A-3 – Tons SO_2 by Strategy

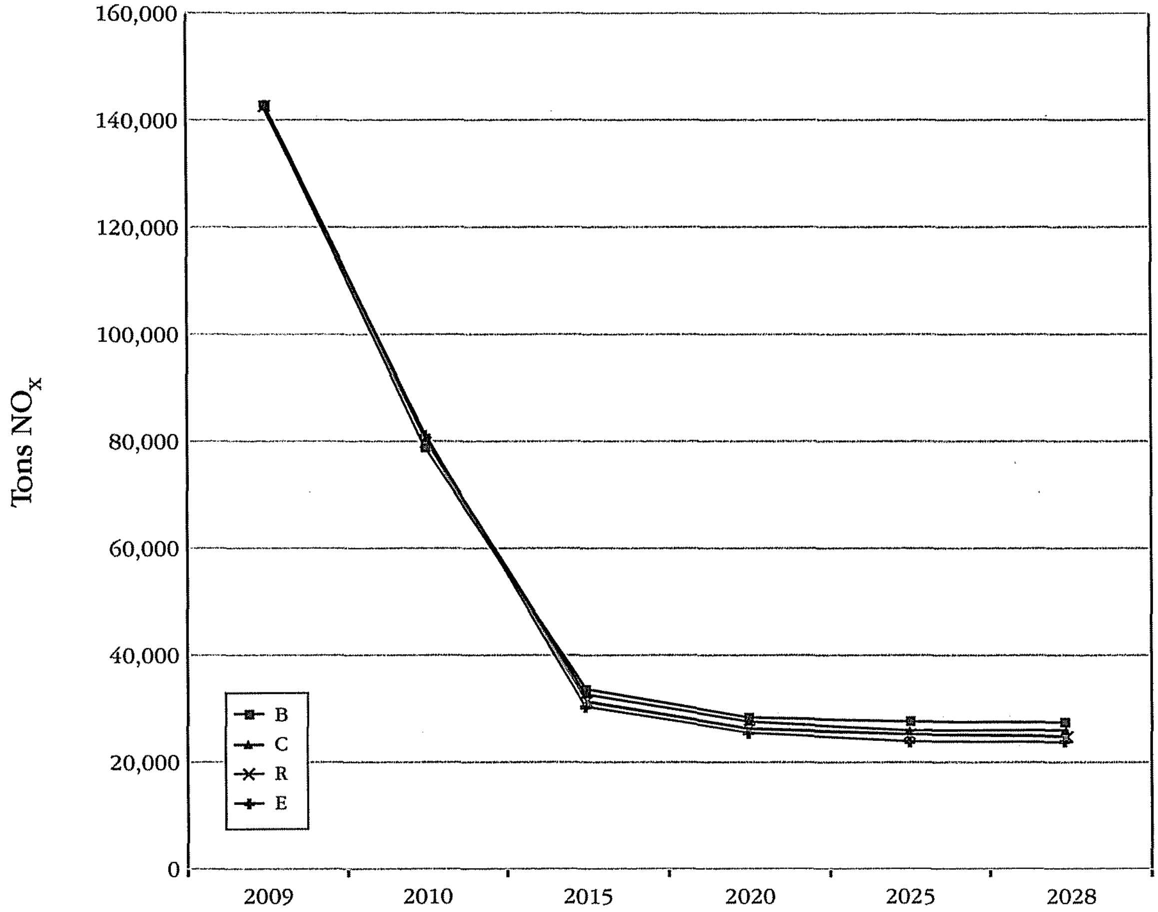


Figure A-4 – Tons NO_X by Strategy

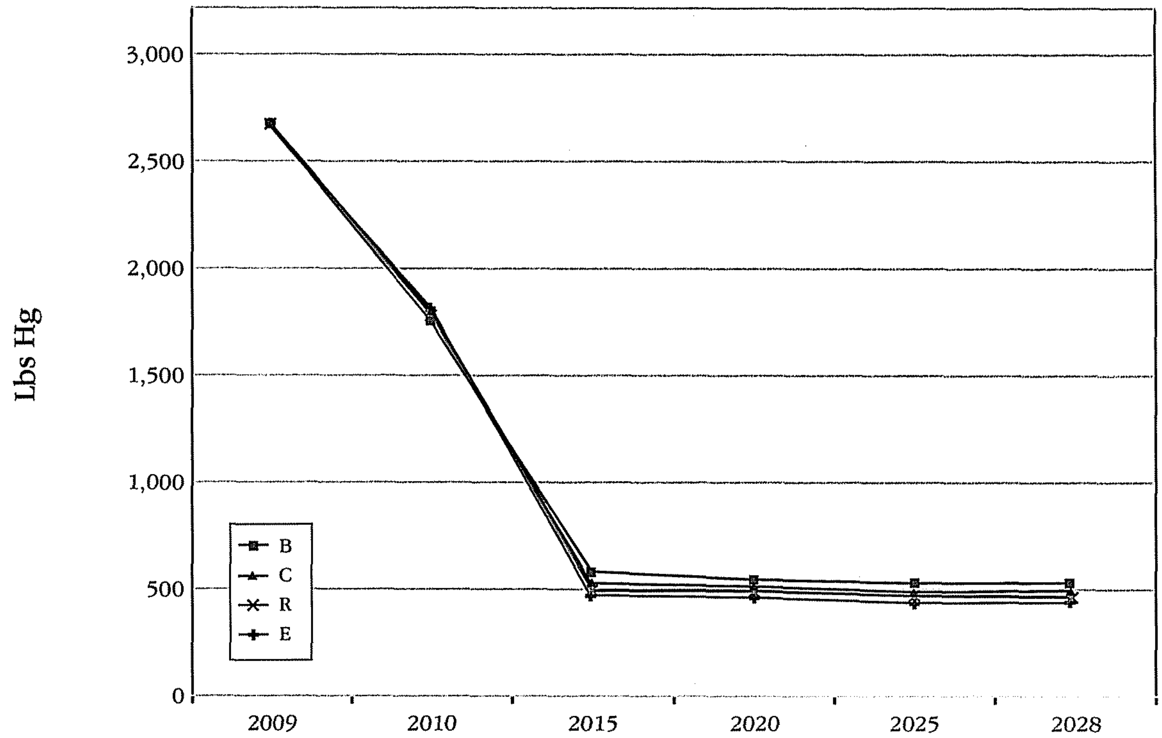


Figure A-5 – Lbs Hg by Strategy

These plots confirm that all emissions decrease over the planning horizon, and thus selecting CO_2 as a surrogate measure was an appropriate proxy for the trend in all air emissions.

To further verify that all evaluated strategies' performance on all four emissions give the same rankings, the total yearly emissions from all sources for each strategy, across all eight scenarios, were summed for five spot years and used to rank the strategies for each emission. Figure A-6 shows the results of these rankings, again confirming that the CO_2 ranking alone gives the same information as using information on all four emissions.

Strategy	SO_2	NO_X	Hg	CO_2
B	4	4	4	4
C	3	3	3	3
E	1	1	1	1
R	2	2	2	2

Figure A-6 – Strategy Rankings for All Four Emissions

Water Impact Metric and Ranking

The major way thermal generating plants impact water is by the amount of heat they reject to the environment. IRP strategies were evaluated on the basis of the BTUs delivered to the plants' condensers, which is where rejected heat is transferred. The calculation involved taking the generation sources shown in Figure A-7 and multiplying their generation (GWh) by heat rate (BTU/kWh) (with unit conversions) by a design factor for the specific generation technology.

Generation Source	Design Factor
Coal	51%
Combined cycle (CC)	11%
Future integrated gasification CC	27%
Future super critical pulverized coal (SCPC)	46%
Lignite	51%
Uranium	66%

Figure A-7 – Design Factors for Generation Sources

The heat rejected to the environment (BTUs) is summed for all five spot years (2010, 2015, 2020, 2025, 2028) and all generation sources for each case, excluding cases associated with Strategies A and D. For each scenario (1–8), the strategies, excluding Strategies A and D, were compared to each other and ranked. A preferred strategy (R) is described by being the most robust, meaning it performs the best across all eight scenarios. Therefore, the rankings of each strategy in each scenario were summed and re-ranked on the basis of their total score. A strategy that performed the best in each of the eight scenarios would have a total score of 8 (1 x 8), and a strategy that performed the worst in all eight scenarios would have a score of 32 (4 x 8). The total scores and associated final ranking is shown in Figure A-8.

Scenarios	Strategies			
	B	C	E	R
1	4	3	1	2
2	4	2	1	3
3	4	3	1	2
4	4	3	1	2
5	4	3	1	2
6	4	3	1	2
7	4	3	1	2
8	4	3	1	2
Sum of Rankings	32	23	8	17
Final Ranking	4	3	1	2

Figure A-8 – Final Strategy Water Impact Ranking

Waste Calculations

The metric used to rank strategies in terms of their waste impact (coal and nuclear) was the cost of handling the waste generated—the assumption is that the costs of disposal, in accordance with all applicable regulations, is a proxy for the wastes' impacts on the environment. Handling costs are based on actual, historical TVA averages, and expected future handling costs are based on operations and transportation estimates.

Coal waste comes from two sources: coal burning and scrubber sludge. Coal waste for TVA plants was calculated using weighted coal ash[1] and heat content (BTU/lb) values from 2009 historical data. The weighted averages are shown in Figures A-9 and A-10.

Year	Strategy			
	B	C	E	R
2010	8.19%	8.19%	8.19%	8.19%
2015	8.04%	7.91%	8.15%	7.85%
2020	8.04%	7.91%	8.15%	7.85%
2025	8.04%	7.91%	8.15%	7.85%
2028	8.04%	7.91%	8.15%	7.85%

Figure A-9 – Weighted Ash Percentage

Year	Strategy			
	B	C	E	R
2010	11,033	11,033	11,033	11,033
2015	11,004	10,948	11,134	10,941
2020	11,004	10,948	11,134	10,941
2025	11,004	10,948	11,134	10,941
2028	11,004	10,948	11,134	10,941

Figure A-10 – Weighted Heat Content (BTU/lb)

For each evaluated strategy, from the model results, the fuel consumed (mmBTU) for TVA coal was multiplied by one million to get the units into BTUs, then multiplied by the coal fuel conversion values (from the weighted BTU/lb figure), and then multiplied by the percentage ash value (from the weighted ash figure). The product was then divided by 2000 to get an answer in tons. A handling cost ($/ton) was then applied to the calculation.

Coal waste from the lignite plant under contract to TVA was calculated based on fuel consumed (mmBTU), divided by 5,234 BTU/lb, multiplied by 14.64 percent ash content (based on Mississippi lignite source information) and divided by 2000 to get an answer in tons. A handling cost ($/ton) was then applied to the calculation.

Coal waste from future Integrated Gasification Combined Cycle (IGCC) was calculated by multiplying generation times 62lb/MWh (slag production) and divided by 2000 to get an answer in tons. For 2010 scrubber waste, waste was calculated by taking fuel consumed (mmBTU), multiplied by 0.5 (about 50 percent of TVA generation is now scrubbed), then

[1]Coal ash consists of both fly and bottom ash

multiplied by 11 lbs/mmBTU (average of TVA existing fleet). For future year calculations, it was assumed that all remaining TVA coal generation (based on coal-fired idling assumptions) are scrubbed. Waste was calculated by multiplying fuel consumed by 11 lbs/mmBTU. A handling cost ($/ton) was then applied to the calculation.

The combined coal and nuclear waste handling costs were used to rank all strategies, excluding Strategies A and D. All coal waste costs, including lignite and future base generation, and nuclear waste costs were summed for all five spot years (2010, 2015, 2020, 2025, 2028) and all generation sources for each case, excluding cases associated with Strategies A and D. For each scenario (1–8), the evaluated strategies were compared to each other and ranked with the strategy having the lowest waste handling cost (ranked #1) and the strategy with the highest costs (ranked #4).

A preferred strategy is the most robust, meaning it performs the best across all eight scenarios. Therefore, we summed the rankings of each strategy in each scenario, and re-ranked them on the basis of their total score. A strategy that performed the best in each of the eight scenarios would have a total score of 8 (1 x 8), and a strategy that performed the worst in all eight scenarios would have a score of 32 (4 x 8). The total scores and associated final ranking is shown in Figure A-11.

Scenario	Strategy B	Strategy C	Strategy E	Strategy R
1	4	3	1	2
2	4	2	1	3
3	4	3	1	2
4	4	3	1	2
5	4	2	1	3
6	4	3	1	2
7	4	3	1	2
8	4	2	1	3
Sum of Rankings	32	21	8	19
Final Ranking	4	3	1	2

Figure A-11 – Final Strategy Waste Impact Ranking (Based on Total Coal and Nuclear Waste Disposal Costs)

Appendix B – Method for Computing Economic Impact Metrics

Purpose

Economic metrics are included in the IRP scoring to provide a general indication of the impact of each strategy on the economic conditions in the TVA service area. The impacts are represented by the change in total employment and personal income indicators as compared to the impacts under Strategy B – Baseline Plan Resource Portfolio, in Scenario 7 – Reference Case: Spring 2010.

Process

The process used is the same as has been used by TVA for programmatic region-wide EIS studies dating back to the 1979-1980 PURPA study and is also used by other models and studies. As shown in Figure B-1, direct expenses by TVA in the region for labor, equipment and materials stimulate economic activity. At the same time, the costs of electricity for customers (the bills customers pay, including savings from energy efficiency) reduces customers' income, which could be used to buy goods and services in the region.

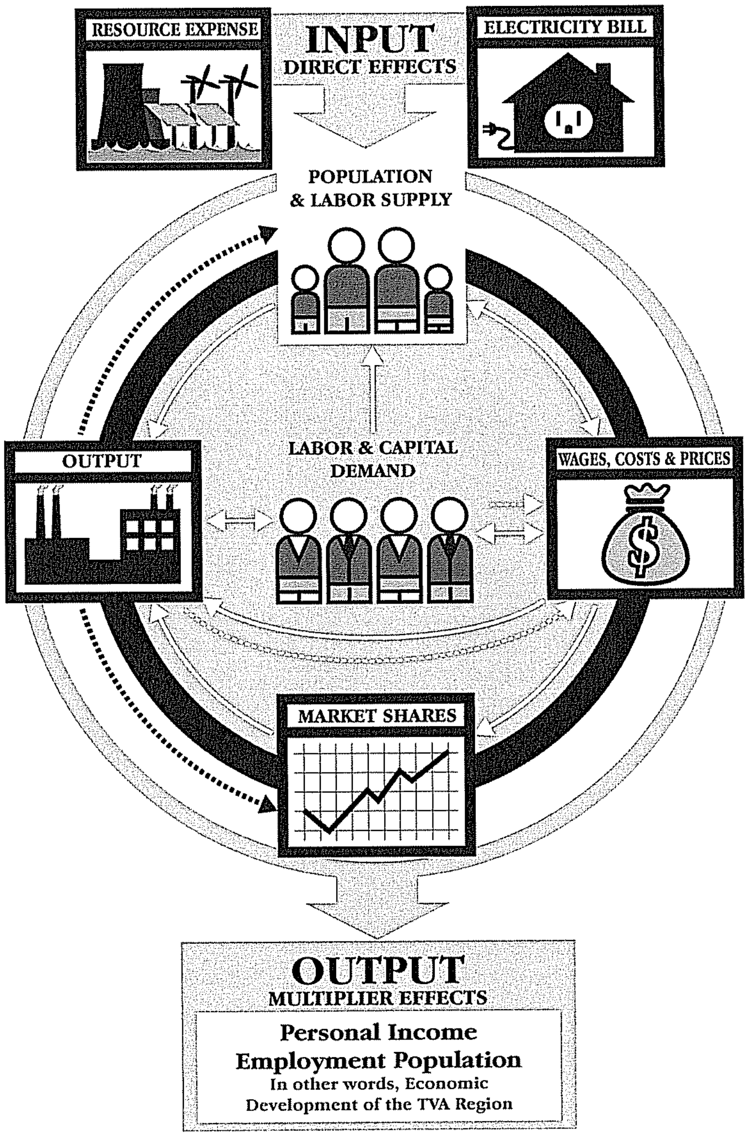


Figure B-1–Input and Output Impacts

These "direct effects" are input into a regional economic model, which captures the interactions within the regional economy—the so-called multiplier effect. TVA uses a Regional Economic Models Inc. (REMI) model of the economies of the TVA region and surrounding areas.

This model maps the TVA region's economic structure, its inter-industry linkages and responses to TVA rate and customer cost changes, including changes from energy efficiency. The model also captures interactions with areas outside the region, such as coal purchases.

The analysis includes data on direct TVA expenditures, including applicable payrolls, material and supply purchases and fuel costs for all energy resource options that comprise a particular strategy for both construction and operations. It also includes data on TVA rates and total resource costs resulting from each strategy, as well as savings to customer bills from energy efficiency and demand reduction programs.

Methodology

Annual construction expenses were entered into the regional economic model for each strategy and scenario analyzed. The model then calculated two types of indirect effects from these construction expenses:

1. Increases in goods manufactured in the TVA region resulting from purchasing materials and supplies associated with a project
2. Additional income generated in the regional economy resulting from the spending of workers hired for construction

The analysis of operations was similar to the construction analysis. Annual operations expense data for the strategy portfolio was entered into the economic model. Since most fuel purchases came from outside the region, they were entered into the analysis as expenses in areas outside the region.

The analysis also estimated the effects of cost differences among strategies. Differences in customer costs or electric bills either add to or subtract from the spending capacity of customers. Therefore, the differences affect the amount of income and revenue available for other uses.

When the income is returned to the economy, it generates additional economic growth. Estimates of annual total resource costs for each strategy, as well as net savings from energy efficiency and demand reduction programs, were used to estimate net cost differences among strategies. The net cost differences were used with the TVA regional economic model to compute the impacts.

Analysis

All IRP strategies were analyzed for Scenario 1 and Scenario 6. These scenarios were used to define the upper and lower range of the impacts on the various strategies. The factors discussed above were incorporated into the regional economic model for each strategy and scenario to measure the overall economic development effects.

Overall, economic impacts are the net effect of both resource expenses and customer electricity bills. Both factors are measured in terms of employment and income changes from the base case, represented in Strategy B – Baseline Plan Resource Portfolio, in Scenario 7 – Reference Case: Spring 2010.

Findings

The major finding is that there was no significant change in both the short- and long-term for the range of strategies and scenarios.

Even though none of the strategies had significant differences from the base case, there were minimal differences of 1 percent or less for each strategy. The differences are outlined in Figure B-2.

		Percent Difference from IRP Reference Portfolio			
		Total Employment		Total Personal Income	
Strategy	Scenario	Average 2011-2028	Average 2011-2015	Average 2011-2028	Average 2011-2015
A	1	0.1%	-0.4%	0.1%	-0.2%
	6	-0.4%	-0.4%	-0.4%	-0.3%
B	1	1.0%	0.3%	0.8%	0.3%
	6	-0.3%	-0.4%	-0.3%	-0.3%
C	1	0.9%	0.2%	0.6%	0.2%
	6	0.2%	-0.2%	0.1%	-0.1%
D	1	1.2%	0.4%	1.0%	0.3%
	6	-0.1%	-0.4%	-0.2%	-0.4%
E	1	0.8%	0.0%	0.6%	0.0%
	6	0.3%	-0.1%	0.2%	-0.1%
R	1	0.9%	0.2%	0.7%	0.2%
	6	0.2%	-0.2%	0.1%	-0.1%

Scenario
1 Economy Recovers Dramatically
2 Environmental Focus is a National Priority
3 Prolonged Economic Malaise
4 Game-Changing Technology
5 Energy Independence
6 Carbon Legislation Creates Economic Downturn
7 *Reference Case: Spring 2010*
8 Reference Case: Great Recession Impacts Recovery

Planning Strategy
A Limited Change in Current Resource Portfolio
B Baseline Plan Resource Portfolio
C Diversity Focused Resource Portfolio
D Nuclear Focused Resource Portfolio
E EEDR and Renewables Focused Resource Portfolio
R *Recommended Planning Direction*

Reference Portfolio: Spring 2010 is Scenario 7, Strategy B

Figure B-2- Final Summary Economic Impacts of IRP Cases

Listed below is an outline of the strategies and analysis results:

- Strategy A performed worse than any of the other strategies for the scenario range
- Strategies B, C, D and E had more comparable results, with only a few tenths of a percent difference
- The impacts of Strategies B and D were very similar
- Both strategies performed better in the high growth Scenario 1 than Strategies C or E
- However, both strategies performed worse in the low growth Scenario 6 than Strategies C or E or the reference portfolio
- These results are consistent with strategies that lean toward building to meet load
- On the other hand, Strategies C and E lean toward conservation
- Strategy C and Strategy E's impacts were very similar
- Both performed above the reference portfolio in the long-term for both Scenarios 1 and 6
- The Recommended Planning Direction results are similar to the results for Strategy C

Method for Computing Economic Metrics

Appendix C – Energy Efficiency and Demand Response

Previous: Demand-Focused Portfolio

In May 2007, the TVA Board of Directors adopted a strategic plan that recognized the need for a comprehensive approach to meet the Tennessee Valley region's future electrical power needs, including increased energy efficiency and demand response (EEDR) initiatives. On May 19, 2008, the TVA Board of Directors approved the guiding principles of an EEDR plan, which included recommendations for reducing the growth in peak demand by up to 1,400 MW by the end of 2012.

The plan recognized that improving peak demand reduction can help slow demand growth in a cost-effective manner while addressing air pollution and global climate change. TVA recognized this goal could only be achieved through a broad cooperative effort with strong support from TVA's customers and stakeholders.

At this time, TVA did not have an energy reduction goal. Therefore, TVA's EEDR program efforts were targeted to achieve the maximum power demand reductions during the periods of highest demand on the TVA system. TVA's existing energy efficiency programs would reduce energy consumption over all hours of the day, but were designed to achieve maximum effect on the peak periods in the early years of the plan. Under this goal, achievements for EEDR programs were measured in MW.

Renewed Vision: To Become a Leader in Energy Efficiency

Since 2007, changes in economic, environmental and power supply market conditions, along with the initiation of TVA's IRP process, provided additional opportunities to assess the potential of energy efficiency program contributions to TVA's resource mix. From the additional work of this IRP and benchmarking research of other utilities in the Southeast, in August 2010, the TVA Board of Directors adopted a renewed vision – to become one of the nation's leading providers of low-cost, cleaner energy by 2020.

To help achieve this renewed vision, TVA set a goal to lead the Southeast in increased energy efficiency by achieving 3.5 percent of sales in energy efficiency savings by 2015. Therefore, EEDR will track both energy and demand savings, and achievements for energy efficiency programs will be measured in GWh.

The actual measure of this effort is the sum of total program results that have the net effect of reducing future load requirements by 3.5 percent. This percentage would result in an energy savings of about 6,000 GWh by the end of 2015. Meeting this goal would:

- Save residential and commercial power customers more than $350 million in FY15
- Provide 1,900 MW of extra power capacity on the TVA system
- Prevent TVA from having to build at least two new power plants

Achievements in FY10 toward the new goal resulted in 211 GWh of energy savings – enough to power about 13,000 homes and avoid carbon emissions equal to 22,700 vehicles. For FY11, TVA has increased its energy efficiency goal to 550 GWh and its associated budget by 50 percent to $135 million. Additional steps in the process to achieve this goal include:

- Refocusing of existing energy efficiency program incentives from demand to energy
- Third-party potential study with renewed energy goal focus amidst today's economic climate
- Development of a five-year EEDR action plan for achieving greater energy savings and to begin implementing new programs by the start of FY12

Program Infrastructure to Support Renewed Vision

TVA's energy efficiency strategy includes incentive programs, price structure changes and education efforts to raise awareness and encourage smart consumer choices. Currently, TVA offers eight energy efficiency programs through participating power distributors under the TVA EnergyRight® Solutions brand.

In May 2009, TVA added the three following programs for residential, business and large industrial markets: In-Home Energy Evaluation, EnergyRight® Solutions for Business and the Major Industrial Program.

Portfolio Design

Energy efficiency and demand-side management programs have been a part of TVA's energy supply resource mix since the late 1970s. The programs were initiated in response to the rising cost of energy and construction of new electric generating units. These programs promoted energy conservation and the efficient use of electricity.

From 1975 to 1988, TVA's efforts resulted in a 1,200 MW reduction in peak demand and more than 3,200 GWh of annual energy savings. These efforts positioned TVA as a national leader in energy efficiency improvements. TVA's achievement was a result of programs such as home energy audits, energy-efficient equipment and weatherization installations. During this period, TVA had a direct impact on the energy efficiency of more than one million homes in the Tennessee Valley region.

In the 1990s, TVA's focus shifted toward the promotion of energy-efficient electro-technologies. The aim was for end users to adopt these technologies when it was economically sensible, in terms of their total energy cost. These programs also delivered demand reduction benefits.

Subsequently, from 1996 to 2008, TVA programs offered in conjunction with distributors of TVA power resulted in a cumulative demand reduction of more than 545 MW. Nearly 90 percent of this total was derived from TVA's EnergyRight® residential program. The program provides items such as low-interest heat pump loans and incentives for energy efficient new home construction. The remaining percentage of the reduction was attributed to residential direct load control programs for air conditioning and water heating and large commercial and industrial programs.

About TVA and Power Delivery Structure

As a wholesale provider of electricity, TVA's operational structure has unique distinctions. TVA differs from prevalent, vertically-integrated utilities because it does not have direct interaction with the majority of end-use consumers.

TVA sells the power it produces to 155 municipal and cooperative power distributors who in turn sell that power to end-use consumers, both residential and commercial. The distributor community is made up of independently operated companies. TVA also directly serves 56 large industries and federal agencies across its service territory.

TVA Program Development

In 2007, TVA retained the services of PA Consulting (PA) to identify potential demand reduction-focused programs that could be implemented to reduce summer peak demand by 1,400 MW in 2012. The recommendations PA provided were derived from a review of industry programs and selected based on economic capability. TVA reviewed PA's designs for applicability to the TVA market, and the programs were prioritized for customization to the demographic and climatic parameters of the region. The programs were prioritized based on qualitative factors to select candidates for design that were highly likely to succeed.

Once preliminary program designs were constructed, the estimated costs and system impacts were documented in a format to permit financial analysis. These inputs were reviewed for consistency and used to create a load shape for each program effort. The load shapes and financial inputs were subjected to a basic financial review to determine their scores on the typical evaluation tests of Total Resource Cost (TRC), Utility Cost Test (UCT) and Rate Impact Measure (RIM).

Performance against these tests was used to fine-tune the program designs to achieve positive impacts. Once the program designs were solidified, more detailed analysis was performed when the load shapes and costs were compared to other resource options in the IRP modeling process.

Because TVA does not serve the majority of end users directly, its program design process includes not only consumer research, but also close involvement by the power distributor community. TVA and distributors coordinate these design activities through the Tennessee Valley Public Power Association's (TVPPA) Energy Services Committee.

TVA's development process was driven by customer insight gained through primary market research conducted with distributors and their customers. Initial program hypotheses were derived from regional market segment data and secondary research on successful programs from across the country. The hypotheses were tested and refined through qualitative and quantitative market research to craft program concepts that best fit TVA's unique relationship with distributors and their customers.

Once program concepts had been refined, TVA worked with distributors and TVPPA to develop program delivery mechanics needed to successfully offer new programs for residential, commercial and industrial customers, as well as education and outreach initiatives. The programs were further refined through market testing prior to system-wide expansion. This process considerably enhances TVA's potential for success and to help keep electricity rates low.

Currently, TVA is engaged in evaluating these new programs and their delivery process following test markets in FY10 and expansion for FY11. These programs will continue to evolve in response to new assumptions, influences and research and market test results. TVA is also establishing measurement and verification protocols to evaluate programs, validate assumptions in program design, document verifiable program impacts and influence new program development.

By using energy more efficiently, the amount of electricity TVA needs to generate to meet the power demand of more than nine million consumers in the Tennessee Valley region will reduce. When fully implemented, these programs will help:

- Reduce reliance on power purchased from other suppliers
- Reduce the impact of power production on the environment
- Mitigate rate pressures by providing direct benefits to the TVA system and consumers

TVA's Long-Term Plan

TVA's view is that EEDR improvement over the long term ultimately must be accomplished through a transformation in the marketplace. The transformation would increase consumer demand for energy-efficient products and services and provides the delivery channels to meet their needs.

The transformation will not be made through TVA purchasing the marketplace, but rather by accomplishing the following important supporting mechanisms:

- Educating the public to make informed choices about their energy use and energy-related purchases
- Electricity rates that send appropriate price signals to encourage consumers to reduce usage during periods of high demand
- Advanced electric metering and other technologies that allow communication between end users and their power provider

- A strong, vibrant infrastructure for end-use generation technologies
- A robust network of commercial providers offering a wide array of energy-efficient products and services
- Exploration and development research of end-use efficiency technology

Program Offerings and Initiatives

TVA continues to offer programs under the EnergyRight® Solutions brand that include residential, commercial, industrial, renewable, education/outreach and demand response initiatives. Figure C-1 outlines existing and new EEDR programs.

Type of Program	Program Name
Energy efficiency	New Homes Plan Heat Pump Plan Water Heater Plan Manufactured Homes Plan Do-It-Yourself Home Energy Evaluation In-Home Energy Evaluation Program EnergyRight® Solutions for Business Major Industrial Program
End-use generation	Generation Partners℠ Green Power Switch®
Demand response	Commercial and Industrial Demand Response Pilot Direct Load Control Program Conservation Voltage Reduction Program (new)
Education and outreach	National Theatre for Children Alliance to Save Energy Green Schools Program Trade Ally Network Internal Energy Management Program (IEMP)

Figure C-1 – Existing and New EEDR Programs

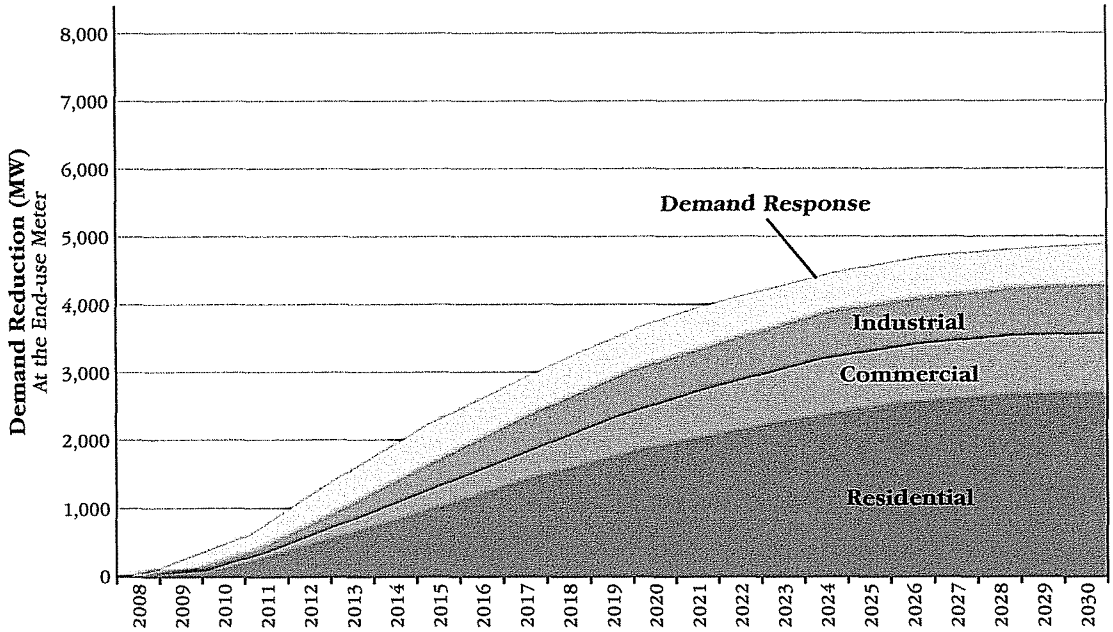


Figure C-2 – EEDR Program Demand Reduction (MW)

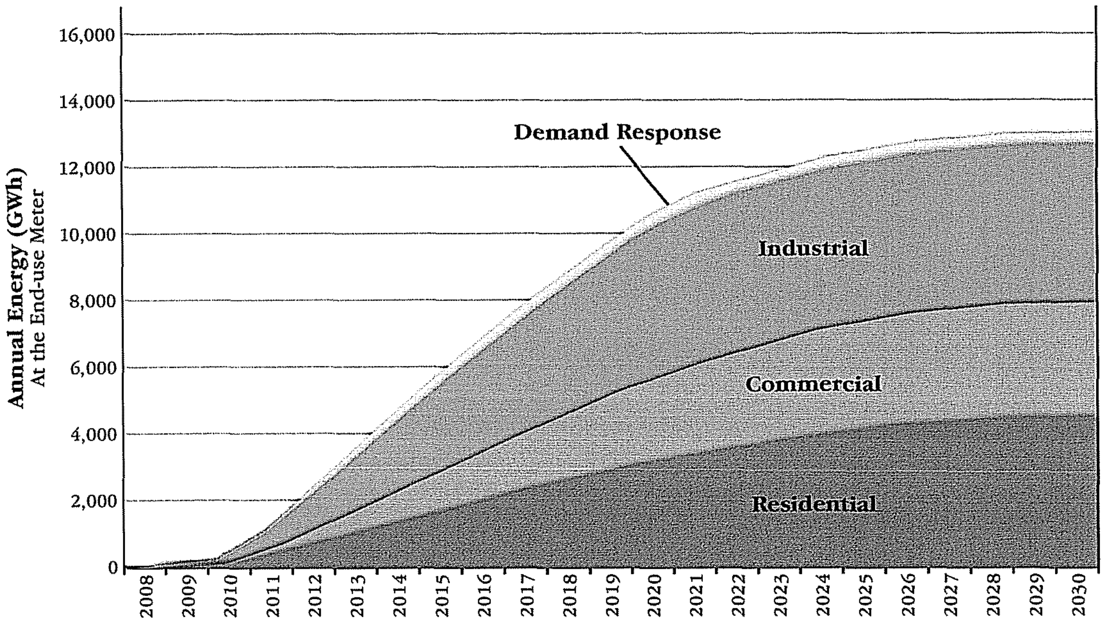


Figure C-3 – EEDR Program Energy Savings (GWh)

Next Steps

The EEDR portfolios used by the IRP process are shown in Figures C-2 and C-3. TVA is building on the results of the analyses performed in the process and refining the EEDR portfolio contained in the Recommended Planning Direction into a more expansive, fully defined five-year plan to accomplish the energy and demand savings identified. As such, the modest post 2020 range for EEDR growth does not preclude further investments in these resources during the decade. Development of the five-year plan will involve improvement of existing efforts as well as implementation of new program designs.

Appendix D – Development of Renewable Energy Portfolios

TVA's Current Renewable Energy Landscape

In addition to nuclear energy and energy efficiency, expansion of TVA's long history as a renewable energy provider can help achieve TVA's renewed vision for a cleaner and more secure energy future, with less reliance on carbon intensive sources of generation. In addition, a federal renewable energy standard (RES) or, alternatively, a clean energy standard, is expected to be adopted within the next few years, prior to enactment of any additional state-level Renewable Portfolio Standards (RPS) requirements in the Tennessee Valley region.

TVA defines renewable energy as energy production that is sustainable and often naturally replenished (e.g., solar, wind, methane, biomass, geothermal and hydro). There is currently no federal statutory definition of renewable energy resources, but recent federal renewable energy legislative proposals would exclude most of TVA's extensive 3,300 MW conventional hydropower installations. Therefore, TVA has been taking significant strides to increase the non-conventional hydro renewable energy portfolio.

These actions are being taken in part to reduce the risk associated with potential renewable energy requirements, and more importantly, to align with the approved TVA Board of Directors renewed vision, policies and other strategic aspirations (e.g., Strategic Plan, Environmental Policy, Renewable and Clean Energy Guiding Principles, Federal Renewable Portfolio Standard Compliance for Customers, State RPS Compliance for Customers). Actions to date that support these policies are described below:

- Since 1992, TVA has increased generating capacity at its conventional hydropower plants by 565 MW through the Hydro Modernization Program (HMOD). Generation associated with these HMOD improvements could be eligible to meet federal RPS
- Green Power Switch® (GPS) was launched in 2000 to offer Tennessee Valley residents the choice to support renewable energy. 100 percent of the renewable energy produced from GPS is from Tennessee Valley resources, including 14 solar sites, 18 wind turbines, two methane gas sites and nearly 400 Generation Partners solar and wind installations. The GPS program was the first green power pricing program in the Southeast and currently has approximately 12,000 participants. GPS is sold to residential and business consumers in 150 KWh blocks. Each block is $4, which is added to the consumers' power bill each month
- Generation Partners℠ (GP) was launched as a pilot program in 2003 and provides technical support, incentives and premium rates to purchase energy from small-scale (<200 kW) renewable generation systems from eligible resources such as solar photovoltaics, wind, biomass and small hydro. The renewable power generated from GP currently goes towards GPS supply. In the winter of 2009, GP capacity was close to 9 MW, made up of approximately 1 MW of biomass, 7 MW of solar and a little less than 1 MW in wind
- The TVA Board of Directors authorized the purchase of up to 2,000 MW of renewable and clean energy. By February 2011, more than 1,600 MW of solar, wind and methane contracts had been signed. Other proposals are being evaluated
- TVA developed a renewable power purchase plan, known as the Renewable Standard Offer, to further encourage small renewable energy projects in the service territory. This initiative offers a set price for renewable energy projects from 201 kW to 20 MW. The first agreement was signed under this program in January 2011 with Waste Management Renewable Energy LLC for a 4.8 MW landfill gas (i.e., methane) facility

Considering all of these efforts, TVA's current 2012 estimated non-conventional hydro renewable energy portfolio, including commitments for renewable resources not yet online, is approximately 1,800 MW.

Further, TVA is taking initiatives that will advance development of renewable energy efforts, including:

- Completing a biomass conversion feasibility, fuel supply and cost assessment study
- Collaborating with the Tennessee Valley and Eastern Kentucky Wind Working Group to update Tennessee Valley wind energy resource assessments and transmission capabilities using newer wind turbine technology and taller towers
- Partnering with the State of Kentucky to evaluate Kentucky renewable energy resources
- Reviewing waste heat recovery capabilities
- Collaborating with Tennessee Solar Institute to host a solar forum in late 2011
- Partnering to explore a variety of smart grid technologies designed to increase energy efficiency
- Involvement in a multi-partner initiative, called the Electric Vehicle Project, which is the largest deployment of electric vehicles and charging infrastructure in history

Renewable Energy Needs

In 2007, North Carolina became the first state in the Southeast to adopt a RES and energy efficiency standard. Investor-owned utilities operating in North Carolina will be required to meet up to 12.5 percent of their retail sales through renewable energy resources or energy efficiency measures by 2021.

The combination of TVA's renewed vision, the growth in customer demand for renewable energy, the increasing regulatory stringency related to coal burning sources of generation and the anticipation of future federal and state mandates is prompting TVA to move towards generation that reduces or eliminates emissions altogether. Renewable energy is a generation resource that meets many of these challenges. Renewables aid in the reduction of air emissions from electric generation activities and use readily available "fuel" sources that are easily replenished.

IRP Renewable Additions

Two renewable energy portfolios were developed for use in the IRP modeling process in summer and fall 2010. This appendix provides background on information needed by modelers, development of estimates and assumptions common to all portfolios, preparation of 2,500 MW and 3,500 MW portfolios and recent/ongoing events.

Modeling Process

IRP scenarios were developed using two different fixed and given schedules for the introduction of new renewable capacity at TVA, including both self-builds and long-term PPAs. One renewables portfolio was developed to achieve a target of 2,500 MW of new renewable generating capacity (busbar) by 2020. The other portfolio was developed to achieve a target of 3,500 MW of new renewable capacity by that same year.

These portfolio development schedules were designed to be feasible and reasonable in terms of achievability, current and future cost, resource availability and diversity, and federal renewable energy and tax policies. They were intended to be treated in expansion planning models as "must-take" capacity for the Draft IRP (i.e., the capacity additions specified in a schedule were incorporated into the system irrespective of any other alternatives or their costs). This ensures that the scheduled quantities are included in a modeling output no matter the other features of the scenario. The approach was initially applied so the schedule also represented the maximum limit of renewable capacity additions. Subsequent tests were run allowing the model to choose between four different portfolios for the final IRP.

Model Inputs

Inputs provided to model renewable capacity included:

- New renewable capacity at the busbar, by type, by year, in MW (either self-build or PPA)
- Equipment lifetime or PPA term (years)
- Annual capacity factor by year, for intermittent resources (wind and solar) and an assumed hourly profile
- Energy delivered to busbar by year in MWh
- Real "all-in" cost per kilowatt for constructing and operating (including fuel, where applicable) generating equipment over the lifetime and for self-builds (constant 2010 dollars per kW)
- Real "all-in" cost per kW for energy delivery under a PPA over its term (constant 2010 dollars per kW)
- Nominal annual expenditures for use in estimating budget impacts ($ million as spent)

Assumptions for Developing Renewable Portfolios

A number of common assumptions were applied in the development of both the 2,500 MW and 3,500 MW renewable energy portfolios, either across the board or specific to a given resource type. These include:

- Real discount rate (5.5 percent) applied for discounting purposes to all resource types
- Equipment lifetimes or PPA terms by resource type
- Federal investment tax credits, grants and production incentives (except if TVA-owned)
- Capacity factors by resource type
- Per kW all-in cost or cost range by resource type
- A wind generation profile and a solar generation profile representative of Tennessee Valley resources
- Existing or planned capacity already included in power planning models in summer 2010
- Existing or planned capacity not included in power planning models in summer 2010
- Capacity excluded (e.g., existing hydro)

Renewable Resource Types and Components

Figure D-1 shows the resource types, assumed lifetimes, capacity factors, all-in costs and resulting levelized cost.

Resource	Lifetime	Capacity Factor	All-in Cost[1] 2010$/KW	LCOE 2010$/ MWh[2]	Simplifying Assumptions
Hydro modernization	30 years	12%-17%	$454	$30	All cost loaded into first year, including lifetime fuel & O&M
Landfill gas	20 years	85%	$3,851	$38	All cost loaded into first year, including lifetime fuel & O&M. LCOE net of Production Tax Credit
Additional hydro	30 years	33%-45%	$1,688	$40	All cost loaded into first year, including lifetime fuel & O&M
Co-firing (Biomass)	25 years	78%	$3,977-$4,048	$45-$47	All cost loaded into first year, including lifetime fuel & O&M. Revised nominal expenditures
Wind – out-of-Valley (market)	20 years	35%	$4,500	$82	Cost spread over lifetime, one payment per year (revised)
Wind – in Valley	25 years	20%	$4,618	$207	All cost loaded into first year, including lifetime fuel & O&M. Revised nominal expenditures
Dedicated bio-mass (market)	25 years	89%	$7,038	$40	Cost spread over lifetime, one payment per year (revised)
Dedicated biomass (conversion)	25 years	70%	$4,634	$59	All cost loaded into first year, including lifetime fuel & O&M. Revised nominal expenditures
Solar PV	25 years	15%	$5,217	$219	All cost loaded into first year, including lifetime fuel & O&M. LCOE net of tax credits/grants

1 – All-in cost estimates in real 2010$ (including all capital and expense), but excluding any tax incentives.

2 – Levelized Cost of Electricity, real 2010$. Includes relevant tax incentives.

Figure D-1 – Renewable Resource Types and Components

The cost estimates were developed or adapted from a variety of sources, including consultant and industry estimates, internal TVA project estimates and existing PPA price quotes.

Existing and planned renewable capacity already incorporated into power planning by summer 2010 included 580-618 MW of hydro unit modernization and 2 MW of wind in the Tennessee Valley region at Buffalo Mountain (TVA-owned). Existing or planned capacity not already incorporated into power planning in the summer of 2010 included approximately 5 MW of landfill gas (Chestnut Ridge and Middle Point), approximately 3 MW of biomass co-firing at Colbert and Allen coal plants, 27 MW of in-valley wind at Buffalo Mountain (lease agreement with Invenergy) and approximately 2 MW of solar through Generation Partners℠ or other resources.

"New" capacity was set for renewables over and above the amounts listed in Figure D-1. A reasonable deployment schedule was developed for each of the two requested portfolios (2,500 MW and 3,500 MW), with consideration given to the following:

- Cost
- Technology maturity and future advances
- Regional renewable resource availability
- A diversified renewable portfolio strategy
- Anticipated federal legislation/regulation and tax policy

In the Draft IRP, the new renewables were scheduled into the model to meet anticipated renewable energy mandates by 2020. Because of the generally higher cost of renewables and given the use of a model whose objective is minimizing cost of service, the more costly alternatives would not have been picked over more traditional capacity. The modeled portfolio growth in renewables capacity mostly tapers off after 2020 due to higher cost and/or regulatory uncertainty.

The modest post 2020 growth range for renewable energy modeled in the portfolios does not preclude further investments in these resources during the decade. TVA has committed to begin the next IRP effort by 2015. With the development of new data and knowledge the renewable portfolios will be developed further.

An effective improvement of 0.5 percent per year in solar photovoltaic energy output per unit cost was incorporated into the IRP portfolios associated with anticipated technology advancements and declining module cost over time. No other performance or real cost improvements were assumed through 2029 for any of the other resource types. Future market demand and innovation for these resources was dependent on unknown technology-by-technology treatment under future energy and environmental regulation or legislation, as well as future tax policy.

Additional Sensitivities

Sensitivities were explored with targets at 2,000 MW (at a variant of the 2,500 MW portfolio) and at 3,000 MW (at a variant of the 3,500 MW portfolio). These capacity values were targeted for the year 2020. TVA evaluated a model-portfolio selection approach that employed the two core renewable portfolios and the two sensitivities, where the selection of a single portfolio in a model run was driven by a cost criterion that includes costs for emissions and carbon, in addition to traditional cost elements.

Figures D-2 and D-3 contain the capacity values for the 2,500 MW and 3,500 MW renewables portfolios, respectively, prepared for this IRP in summer and fall 2010. These reflect target MW values for the year 2020.

	Net Capacity (MW Cumulative)																	
FY:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
HMOD						9.6	20.2	31.6	42.9	53.9	64.5	74.7	82.8	88.8	88.8	88.8	88.8	88.8
Landfill gas	1.8	3.7	12.0	15.6	18.4	21.4	25.2	27.9	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3
Addl hydro		24.3	24.3	48.6	48.6	75.6	75.6	107.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6
Co-firing		60.0	118.0	118.0	118.0	118.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0
Wind – out-of-Valley (PPA)	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0	1,380.0
Wind – in Valley			50.0	100.0	150.0	200.0	250.0	300.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0
Ded Biomass – PPA		35.0	35.0	67.0	67.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
Ded Biomass – Conv			80.0	80.0	80.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Solar	20.0	25.0	40.0	45.0	60.0	65.0	80.0	85.0	100.0	105.0	120.0	125.0	140.0	145.0	160.0	165.0	180.0	185.0
Total	1,401.8	1,528.0	1,739.3	1,854.2	1,922.0	2,156.6	2,264.0	2,365.1	2,489.8	2,505.8	2,531.4	2,546.6	2,569.7	2,580.7	2,595.7	2,600.7	2,615.7	2,620.7

Figure D-2 – New Renewable Capacity at 2,500 MW

	Net Capacity (MW Cumulative)																	
FY:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
HMOD						9.6	20.2	31.6	42.9	53.9	64.5	74.7	82.8	88.8	88.8	88.8	88.8	88.8
Landfill gas	1.8	3.7	12.0	15.6	18.4	21.4	25.2	27.9	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3
Addl hydro	0.0	24.3	24.3	48.6	48.6	75.6	75.6	107.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6	143.6
Co-firing	0.0	60.0	118.0	118.0	118.0	118.0	141.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
Wind – out-of-Valley (PPA)	1,380.0	1,480.0	1,630.0	1,780.0	1,930.0	2,080.0	2,230.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0	2,380.0
Wind – in Valley			50.0	100.0	150.0	200.0	250.0	300.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0
Ded Biomass – PPA	0.0	35.0	35.0	67.0	67.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
Ded Biomass – Conv	0.0	0.0	80.0	80.0	80.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0
Solar	35.0	45.0	75.0	85.0	115.0	125.0	155.0	165.0	195.0	205.0	235.0	245.0	275.0	285.0	315.0	325.0	355.0	365.0
Total	1,416.8	1,648.0	2,024.3	2,294.2	2,527.0	2,939.6	3,212.0	3,468.1	3,607.8	3,628.8	3,669.4	3,689.6	3,727.7	3,747.7	3,773.7	3,783.7	3,813.7	3,823.7

Figure D-3 – New Renewable Capacity at 3,500 MW

Appendix E – Draft IRP Phase Expansion Plan Listing

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	246	35	-							
2011	408	48	-							
2012	421	137	-	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	666	155	-	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	1733	155	-							
2015	1434	160	-	GL CT Ref	GL CT Ref		GL CT Ref	GL CT Ref		GL CT Ref
2016	1557	160	-							
2017	1684	160	-							
2018	1812	160	-							
2019	1940	160	-							
2020	2051	160	-							
2021	2069	160	-							
2022	2014	160	-							
2023	2061	160	-							
2024	2131	160	-							
2025	2085	160	-							
2026	2226	160	-							
2027	2076	160	-							
2028	1980	160	-							
2029	1905	160	-							

Figure E-1 – Planning Strategy A – Limited Change in Current Portfolio

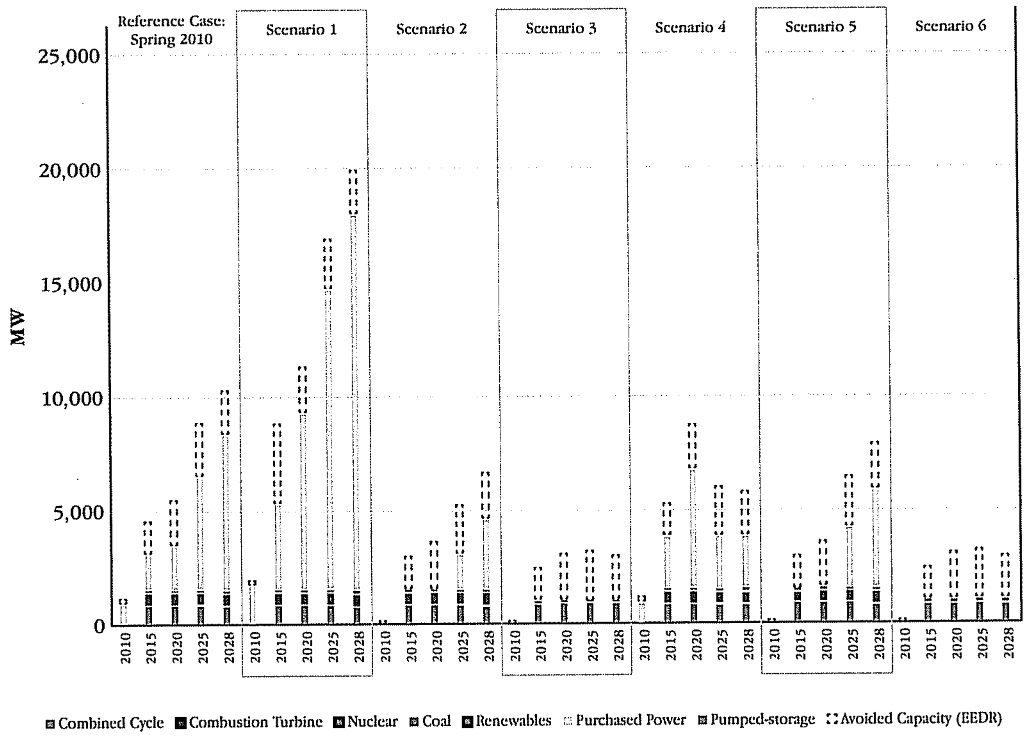


Figure E-2 – Planning Strategy A – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	229	35	-	PPAs & Acq			PPAs & Acq			
2011	385	48	(226)							
2012	384	137	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	610	155	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	1363	155	(935)	CTa CT GL CT Ref			CTa		GL CT Ref	
2015	1496	160	(2,415)	CT CC	GL CT Ref		GL CT Ref CT CC	GL CT Ref		GL CT Ref CTa
2016	1622	160	(2,415)	CT			CT			CT
2017	1751	160	(2,415)	CT			CT			CTa
2018	1881	160	(2,415)	BLN1			BLN1	BLN1		BLN1
2019	2012	160	(2,415)	CT	BLN1					
2020	2124	160	(2,415)	BLN2			BLN2	BLN2		BLN2
2021	2216	160	(2,415)	CC	BLN2					
2022	2294	160	(2,415)	CT CC				CTa		CC
2023	2362	160	(2,415)	CT				CTa		CT
2024	2429	160	(2,415)	NUC						
2025	2470	160	(2,415)	IGCC	NUC			CC		CT
2026	2495	160	(2,415)	NUC						
2027	2509	160	(2,415)	CT	NUC			CT		CT
2028	2516	160	(2,415)	CC						
2029	2520	160	(2,415)	IGCC, Cta	Cta	Cta		CT		CC

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

IGCC = integrated gasification combined cycle (coal technology)

Figure E-3 – Planning Strategy B – Baseline Plan Resource Portfolio

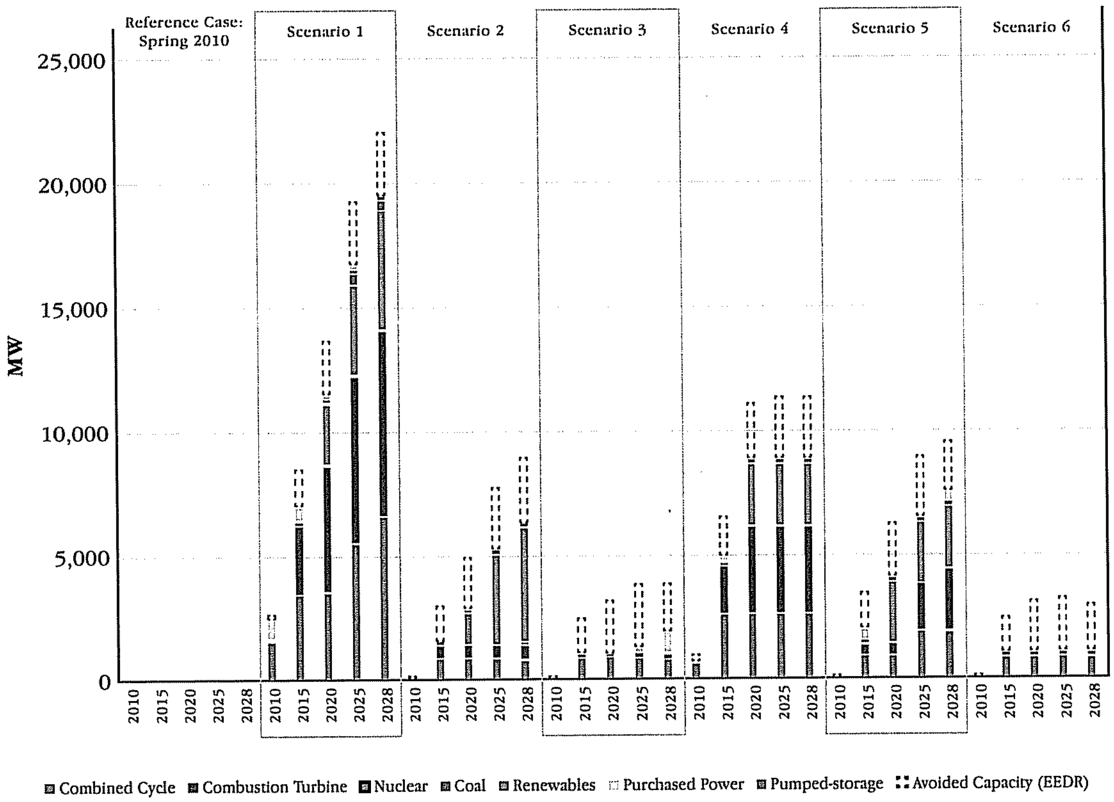


Figure E-4 – Planning Strategy B – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	298	35	-	PPAs & Acq						
2011	389	48	(226)							
2012	770	145	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	1334	286	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	1596	44	(935)	CTa			CTa			
2015	2069	515	(3,252)	GL CT Ref CT CC			GL CT Ref CT CC	GL CT Ref		GL CT Ref CTa
2016	2537	528	(3,252)	CT			CT			
2017	2828	715	(3,252)							
2018	3116	768	(3,252)	BLN1			BLN1			BLN1
2019	3395	822	(3,252)							
2020	3627	883	(3,252)	BLN2 PSH	PSH	PSH	BLN2 PSH	PSH	PSH	BLN2 PSH
2021	3817	896	(3,252)	CT						
2022	3985	911	(3,252)	CC	BLN1			BLN1		
2023	4143	922	(3,252)	CC						
2024	4295	935	(3,252)	NUC	BLN2			BLN2		
2025	4412	942	(3,252)	IGCC						CT
2026	4502	947	(3,252)	NUC						
2027	4561	948	(3,252)	CT						CC
2028	4602	953	(3,252)	CT						
2029	4638	954	(3,252)	IGCC, Cta	NUC			CTa		CTa

Figure E-5 – Planning Strategy C – Diversity Focused Resource Portfolio

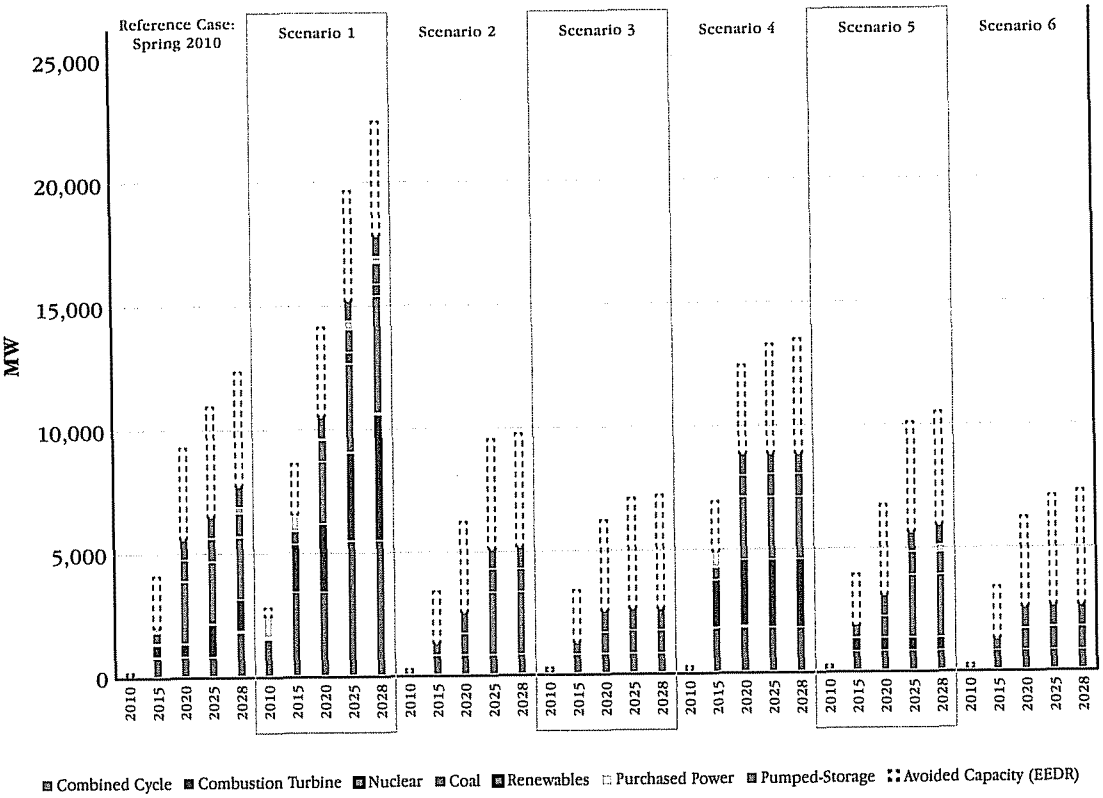


Figure E-6 – Planning Strategy C – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	1300	35	-	PPAs & Acq						
2011	1126	48	(226)							
2012	1394	145	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	1795	286	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	2228	442	(935)	CTa		GL CT Ref	GL CT Ref CT CTa			
2015	2612	515	(5,718)	GL CT Ref CT(2) CC(2)	GL CT Ref		CT(2) CC(2)	GL CT Ref CC		GL CT Ref CTa(2) CC
2016	2846	528	(5,718)	CT			CC	CC		CC
2017	3104	715	(6,972)	CC	CC		CC			CTa
2018	3389	768	(6,972)	BLN1	BLN1		BLN1	BLN1		BLN1
2019	3704	822	(6,972)							
2020	3993	883	(6,972)	BLN2 PSH	BLN2 PSH	PSH	BLN2 PSH	BLN2 PSH	PSH	BLN2 PSH
2021	4092	896	(6,972)							
2022	4040	911	(6,972)	CC (2)						
2023	4042	922	(6,972)							CTa
2024	4303	935	(6,972)	NUC						
2025	4991	942	(6,972)	IGCC	NUC					
2026	5201	947	(6,972)	NUC						
2027	5711	948	(6,972)		NUC					
2028	6198	953	(6,972)	IGCC						
2029	6316	954	(6,972)	SCPC						

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

IGCC = integrated gasification combined cycle (coal technology)

Figure E-7 – Planning Strategy D – Nuclear Focused Resource Portfolio

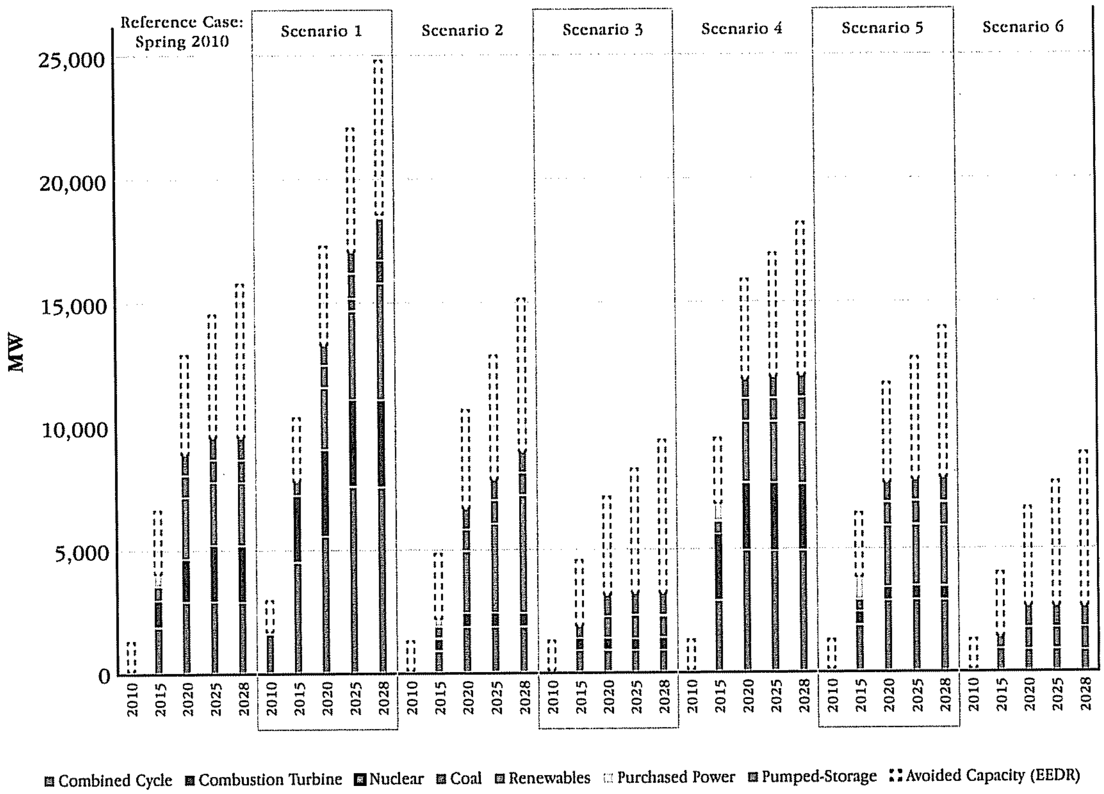


Figure E-8 – Planning Strategy D – Capacity Additions by Scenario

Year	Defined Model Inputs			Capacity Additions by Scenario						
	EEDR	Renewables	Idled Capacity	1	2	3	4	5	6	7
2010	34	35	-	PPAs & Acq						
2011	181	48	(226)							
2012	1136	178	(226)	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC	JSF CC
2013	1664	314	(935)	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2	WBN2
2014	2431	493	(935)							
2015	3479	580	(4,730)	GL CT Ref CTa CC(2)			GL CT Ref CTa CC(2)	GL CT Ref		GL CT Ref CTa
2016	3843	616	(4,730)	CT			CT			
2017	4183	846	(4,730)							
2018	4504	921	(4,730)	CT			CT			CC
2019	4811	994	(4,730)	CC (2)						
2020	5074	1060	(4,730)	CC (2)			CC			
2021	5353	1074	(4,730)	CTa						
2022	5460	1094	(4,730)	BLN1	BLN1			BLN1		BLN1
2023	5599	1107	(4,730)	CT						
2024	5739	1124	(4,730)	BLN2	BLN2			BLN2		BLN2
2025	5815	1133	(4,730)	CT						
2026	5893	1142	(4,730)	CT						CT
2027	5961	1145	(4,730)	CT						
2028	6009	1154	(4,730)	NUC				CTa		CTa
2029	6043	1157	(4,730)	CT				CTa		CTa

Key:

PPAs & Acq = purchased power agreements, including potential acquisition of third-party-owned projects (primarily combined cycle technology)

JSF CC = the combined cycle unit to be sited at the John Sevier plant (TVA Board of Directors' approved project, currently under development)

WBN2 = Watts Bar Unit 2 (TVA Board of Directors' approved project, currently under development)

GL CT Ref = the proposed refurbishment of the existing Gleason CT units

CC = combined cycle

CT/CTa = combustion turbines

PSH = pumped-storage hydro

BLN1/BLN2 = Bellefonte Units 1 & 2

NUC = nuclear unit

Figure E-9 – Planning Strategy E – EEDR and Renewables Focused Portfolio

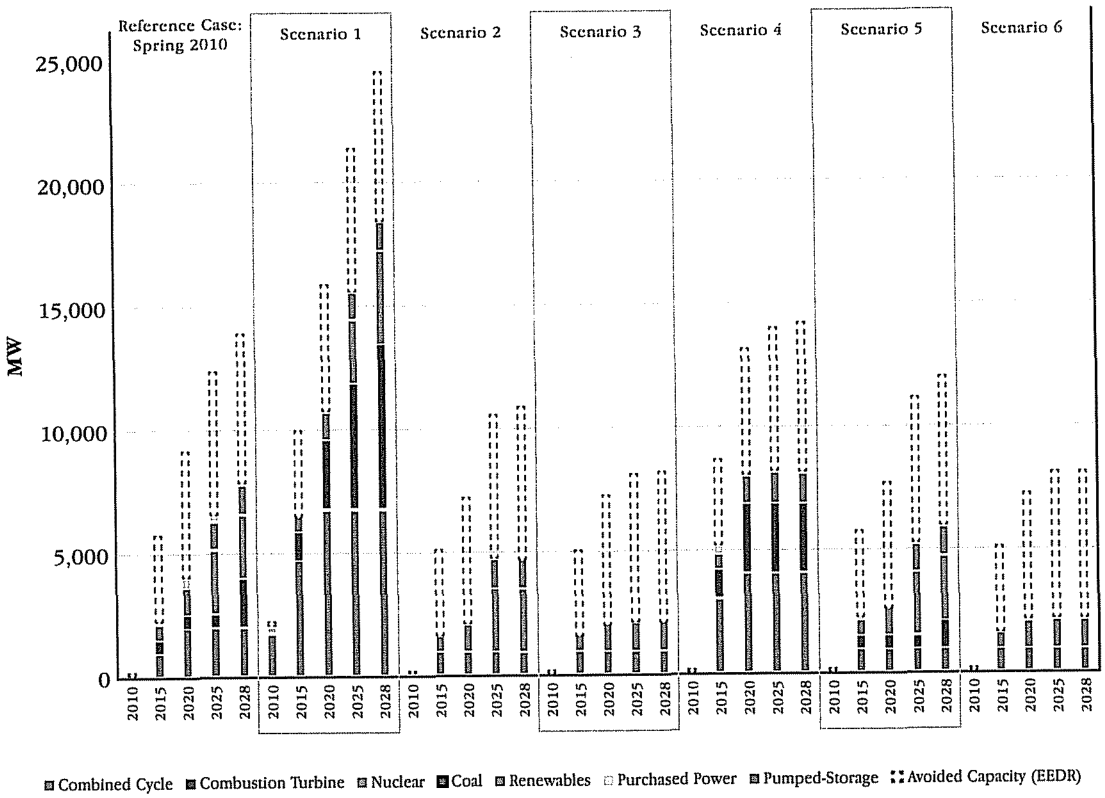


Figure E-10 – Planning Strategy E – Capacity Additions by Scenario

Input from Stakeholders	How Input was Incorporated
• Contribution of EEDR should be increased	• The range of EEDR considered in the planning strategies was broadened in this IRP
• Renewable investment (particularly within the Valley) should be increased	• Renewable portfolios were expanded beyond existing contracts and include in-Valley resources • Additional renewable power can be selected as part of the market supply identified by this IRP
• EEDR and renewable portfolios with significant growth beyond 2020 should be evaluated	• An additional sensitivity with EEDR and renewable portfolios that grew dramatically after 2020 was tested
• Biomass is the most viable renewable resource within the Valley and should be expanded where sustainable	• Biomass was included in the renewable portfolios evaluated in this IRP
• Combined Heat and Power (CHP) should be included as a resource option	• CHP was able to be selected as part of the market supplied power identified in this IRP
• A large amount of the aging coal fleet should be idled • TVA should consider the impacts of more stringent environmental requirements	• Range of idled coal capacity considered was expanded in the development of the planning strategies
• Capability for energy storage should be increased	• A pumped-storage unit was included in the development of the Recommended Planning Direction
• A strategy that does not include nuclear after WBN2 should be considered	• Strategy A did not allow any capital expansion beyond WBN2 • An additional sensitivity was completed to test a "no nuclear" case
• The use of natural gas should be significantly expanded	• The Recommended Planning Direction supported a broad range of potential natural gas capacity expansion
• Price forecast for natural gas should be lower based on emergence of shale gas • Forecast should not change because shale gas has yet to be demonstrated as a reliable source of supply	• Forecast was based upon recent market conditions as well as long-term economic views of the market that include shale gas
• Engagement with distributors is the key to successfully implementing EEDR programs	• TVA is committed to maintaining a strong partnership with the distributors of TVA power
• Distributor-owned generation should be increased	• TVA is engaged in dialogue to identify opportunities for distributor-owned generation outside this IRP
• The public should have more opportunities to interact with the IRP process	• TVA initiated quarterly briefings with the public in November 2009
• TVA should explore alternatives that allow for greater participation in public events	• TVA began broadcasting quarterly briefings via webinar in February 2010 • All meetings during the public comment period (October 2010) were also available via webinar

Stakeholder Input Considered and Incorporated

Input from Stakeholders	How Input was Incorporated
• The debt ceiling should be raised in order to minimize rate impacts from capital expansion	• The IRP scorecard included a short-term rate impact measure • Stakeholder desire for an increased debt ceiling was shared with appropriate groups within TVA
• Potential economic impacts of carbon legislation being implemented were not represented in scenarios	• Scenario 6 – Carbon Legislation Creates Economic Downturn was created to address this concern
• Scenarios should reflect forecasts for demand that are flat and possibly negative	• Scenario 3 – Prolonged Economic Malaise had nearly-flat load growth and Scenario 6 had a load forecast that is slightly negative
• TVA should use "true cost accounting" to monetize all external impacts related to operations	• TVA used industry standard methods for accounting for project and operations cost • Environmental impact measures were included in the IRP scorecard
• A technology innovation metric is out of context for this IRP and should not be included in the IRP scorecard	• Technology innovation metric was dropped, but was included as a separate discussion from the IRP scorecard
• Graphical indicators for economic impact in the IRP scorecard may imply greater differences than actually exist	• The IRP scorecard was modified to show the percentage difference from the baseline for economic impacts
• Strategic metrics should be populated for all planning strategies considered in the Draft IRP	• Process was modified to create fully populated scorecards for all planning strategies
• Other emissions (e.g., SO_2 and NO_x) should be added as a separate environmental measure from CO_2 emissions	• TVA determined that CO_2 emissions were a suitable proxy for other emissions and documented the supporting facts in Appendix A – Method for Computing Environmental Impact Metrics
• New approaches that combine components of different planning strategies should be tested	• Analysis to identify the Recommended Planning Direction optimally selected strategy components
• Requests were received to extend the 45-day public comment period on the Draft IRP	• The public comment period was extended seven days to allow additional time to submit comments
• The IRP should be a recurring process for TVA	• TVA has committed to begin the next IRP effort by 2015

Acronym Index

BLN1/ BLN2 – Bellefonte Nuclear Plants Units 1&2
B&W – Babcock and Wilcox
CAES – Compressed air energy storage
CEQ – Council on Environmental Quality
CC – Combined cycle
CCS – Carbon capture and sequestration
CO_2 – Carbon dioxide
CRP – Conservation Reserve Program
CSP – Concentrating solar power
CT – Combustion turbine
DOE – Department of Energy
EEDR – Energy efficiency and demand response
EERE – Energy efficiency and renewable energy
EIS – Environmental Impact Statement
EPRI – Electric Power Research Institute
EV2020 – Energy Vision 2020
FBC – Fluidized bed combustion
FERC – Federal Energy Regulatory Commission
GWh – Gigawatt hour
HAP – Hazardous Air Pollutant
Hg – Mercury
IGCC – Integrated gasification combined cycle
IRP – Integrated Resource Plan
MACT – Maximum Achievable Control Technology
MAPE – Mean annual percent error
MSW – Municipal solid waste
MW – Megawatt
MWh – Megawatt hour
NEPA – National Environmental Policy Act
NO_x – Nitrogen oxide or Nitrous oxide
NRC – Nuclear Regulatory Commission
NREL – National Renewable Energy Laboratory
NUC – Nuclear unit
PC – Pulverized coal
PPAs – Power purchase agreements
PSH – Pumped-storage hydro
PV – Photovoltaic
PVRR – Present Value of Revenue Requirements
SCPC – Supercritical pulverized coal
SEER – Seasonal energy efficiency ratio
SEIS – Supplemental environmental impact statement
SO_2 – Sulfur dioxide
SRG – Stakeholder Review Group
TVA – Tennessee Valley Authority
TVPPA – Tennessee Valley Public Power Association
WBN2 – Watts Bar Unit 2

EXHIBIT ____

112TH CONGRESS
2D SESSION

S. ____

To amend the Public Utility Regulatory Policies Act of 1978 to create a market-oriented standard for clean electric energy generation, and for other purposes.

IN THE SENATE OF THE UNITED STATES

Mr. BINGAMAN (for himself, ________) introduced the following bill; which was read twice and referred to the Committee on ________

A BILL

To amend the Public Utility Regulatory Policies Act of 1978 to create a market-oriented standard for clean electric energy generation, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "Clean Energy Standard Act of 2012".

SEC. 2. FEDERAL CLEAN ENERGY STANDARD.

Title VI of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.) is amended by adding at the end the following:

SC EXHIBIT 25

"SEC. 610. FEDERAL CLEAN ENERGY STANDARD.

"(a) PURPOSE.—The purpose of this section is to create a market-oriented standard for electric energy generation that stimulates clean energy innovation and promotes a diverse set of low- and zero-carbon generation solutions in the United States at the lowest incremental cost to electric consumers.

"(b) DEFINITIONS.—In this section:

"(1) CLEAN ENERGY.—The term 'clean energy' means electric energy that is generated—

"(A) at a facility placed in service after December 31, 1991, using—

"(i) renewable energy;

"(ii) qualified renewable biomass;

"(iii) natural gas;

"(iv) hydropower;

"(v) nuclear power; or

"(vi) qualified waste-to-energy;

"(B) at a facility placed in service after the date of enactment of this section, using—

"(i) qualified combined heat and power; or

"(ii) a source of energy, other than biomass, with lower annual carbon intensity than 0.82 metric tons of carbon dioxide equivalent per megawatt-hour;

"(C) as a result of qualified efficiency improvements or capacity additions; or

"(D) at a facility that captures carbon dioxide and prevents the release of the carbon dioxide into the atmosphere.

"(2) NATURAL GAS.—

"(A) INCLUSION.—The term 'natural gas' includes coal mine methane.

"(B) EXCLUSIONS.—The term 'natural gas' excludes landfill methane and biogas.

"(3) QUALIFIED COMBINED HEAT AND POWER.—

"(A) IN GENERAL.—The term 'qualified combined heat and power' means a system that—

"(i) uses the same energy source for the simultaneous or sequential generation of electrical energy and thermal energy;

"(ii) produces at least—

"(I) 20 percent of the useful energy of the system in the form of electricity; and

"(II) 20 percent of the useful energy in the form of useful thermal energy;

"(iii) to the extent the system uses biomass, uses only qualified renewable biomass; and

"(iv) operates with an energy efficiency percentage that is greater than 50 percent.

"(B) DETERMINATION OF ENERGY EFFICIENCY.—For purposes of subparagraph (A), the energy efficiency percentage of a combined heat and power system shall be determined in accordance with section 48(c)(3)(C)(i) of the Internal Revenue Code of 1986.

"(4) QUALIFIED EFFICIENCY IMPROVEMENTS OR CAPACITY ADDITIONS.—

"(A) IN GENERAL.—Subject to subparagraphs (B) and (C), the term 'qualified efficiency improvements or capacity additions' means efficiency improvements or capacity additions made after December 31, 1991, to—

"(i) a nuclear facility placed in service on or before December 31, 1991; or

"(ii) a hydropower facility placed in service on or before December 31, 1991.

"(B) EXCLUSION.—The term 'qualified efficiency improvements or capacity additions' does not include additional electric energy generated as a result of operational changes not directly associated with efficiency improvements or capacity additions.

"(C) MEASUREMENT AND CERTIFICATION.—In the case of hydropower, efficiency improvements and capacity additions under this paragraph shall be—

"(i) measured on the basis of the same water flow information that is used to determine the historic average annual generation for the applicable hydroelectric facility; and

"(ii) certified by the Secretary or the Commission.

"(5) QUALIFIED RENEWABLE BIOMASS.—The term 'qualified renewable biomass' means renewable biomass produced and harvested through land management practices that maintain or restore the composition, structure, and processes of ecosystems, including the diversity of plant and animal communities, water quality, and the productive capacity of soil and the ecological systems.

"(6) QUALIFIED WASTE-TO-ENERGY.—The term 'qualified waste-to-energy' means energy produced—

"(A) from the combustion of—

"(i) post-recycled municipal solid waste;

"(ii) gas produced from the gasification or pyrolization of post-recycled municipal solid waste;

"(iii) biogas;

"(iv) landfill methane;

"(v) animal waste or animal byproducts; or

"(vi) wood, paper products that are not commonly recyclable, and vegetation (including trees and trimmings, yard waste, pallets, railroad ties, crates, and solid-wood manufacturing and construction debris), if diverted from or separated from other waste out of a municipal waste stream; and

"(B) at a facility that the Commission has certified, on an annual basis, is in compliance with all applicable Federal and State environmental permits, including—

"(i) in the case of a facility that commences operation before the date of enactment of this section, compliance with emission standards under sections 112 and 129 of the Clean Air Act (42 U.S.C. 7412, 7429) that apply as of the date of enactment of this section to new facilities within the applicable source category; and

"(ii) in the case of a facility that produces electric energy from the combustion, pyrolization, or gasification of municipal solid waste, certification that each local government unit from which the waste originates operates, participates in the operation of, contracts for, or otherwise provides for recycling services for residents of the local government unit.

"(7) RENEWABLE ENERGY.—The term 'renewable energy' means solar, wind, ocean, current, wave, tidal, or geothermal energy.

"(c) CLEAN ENERGY REQUIREMENT.—

"(1) IN GENERAL.—Effective beginning in calendar year 2015, each electric utility that sells electric energy to electric consumers in a State shall obtain a percentage of the electric energy the electric utility sells to electric consumers during a calendar year from clean energy.

"(2) PERCENTAGE REQUIRED.—The percentage of electric energy sold during a calendar year that is required to be clean energy under paragraph (1) shall be determined in accordance with the following table:

"Calendar year	Minimum annual percentage
2015	24
2016	27
2017	30
2018	33
2019	36
2020	39
2021	42
2022	45
2023	48
2024	51
2025	54
2026	57
2027	60
2028	63
2029	66
2030	69
2031	72
2032	75
2033	78
2034	81
2035	84

"(3) DEDUCTION FOR ELECTRIC ENERGY GENERATED FROM HYDROPOWER OR NUCLEAR POWER.—An electric utility that sells electric energy to electric consumers from a facility placed in service in the United States on or before December 31, 1991, using hydropower or nuclear power may deduct the quantity of the electric energy from the quantity to which the percentage in paragraph (2) applies.

"(d) MEANS OF COMPLIANCE.—An electric utility shall meet the requirements of subsection (c) by—

"(1) submitting to the Secretary clean energy credits issued under subsection (e);

"(2) making alternative compliance payments of 3 cents per kilowatt hour in accordance with subsection (i); or

"(3) taking a combination of actions described in paragraphs (1) and (2).

"(e) FEDERAL CLEAN ENERGY TRADING PROGRAM.—

"(1) ESTABLISHMENT.—Not later than 180 days after the date of enactment of this section, the Secretary shall establish a Federal clean energy credit trading program under which electric utilities may submit to the Secretary clean energy credits to certify compliance by the electric utilities with subsection (c).

"(2) CLEAN ENERGY CREDITS.—Except as provided in paragraph (3)(B), the Secretary shall issue to each generator of electric energy a quantity of clean energy credits determined in accordance with subsections (f) and (g).

"(3) ADMINISTRATION.—In carrying out the program under this subsection, the Secretary shall ensure that—

"(A) a clean energy credit shall be used only once for purposes of compliance with this section; and

"(B) a clean energy credit issued for clean energy generated and sold for resale under a contract in effect on the date of enactment of this section shall be issued to the purchasing electric utility, unless otherwise provided by the contract.

"(4) DELEGATION OF MARKET FUNCTION.—

"(A) IN GENERAL.—In carrying out the program under this subsection, the Secretary may delegate—

"(i) to 1 or more appropriate market-making entities, the administration of a national clean energy credit market for purposes of establishing a transparent national market for the sale or trade of clean energy credits; and "(ii) to appropriate entities, the tracking of dispatch of clean generation.

"(B) ADMINISTRATION.—In making a delegation under subparagraph (A)(ii), the Secretary shall ensure that the tracking and reporting of information concerning the dispatch of clean generation is transparent, verifiable, and independent of any generation or load interests subject to an obligation under this section.

"(5) BANKING OF CLEAN ENERGY CREDITS.—Clean energy credits to be used for compliance purposes under subsection (c) shall be valid for the year in which the clean energy credits are issued or in any subsequent calendar year.

"(f) DETERMINATION OF QUANTITY OF CREDIT.—

"(1) IN GENERAL.—Except as otherwise provided in this subsection, the quantity of clean energy credits issued to each electric utility generating electric energy in the United States from clean energy shall be equal to the product of—

"(A) for each generator owned by a utility, the number of megawatt-hours of electric energy sold from that generator by the utility; and

"(B) the difference between—

"(i) 1.0; and

"(ii) the quotient obtained by dividing—

"(I) the annual carbon intensity of the generator, as determined in accordance with subsection (g), expressed in metric tons per megawatt-hour; by

"(II) 0.82.

"(2) NEGATIVE CREDITS.—Notwithstanding any other provision of this subsection, the Secretary shall not issue a negative quantity of clean energy credits to any generator.

"(3) QUALIFIED COMBINED HEAT AND POWER.—

"(A) IN GENERAL.—The quantity of clean energy credits issued to an owner of a qualified combined heat and power system in the United States shall be equal to the difference between—

"(i) the product obtained by multiplying—

"(I) the number of megawatt-hours of electric energy generated by the system; and

"(II) the difference between—

"(aa) 1.0; and

"(bb) the quotient obtained by dividing—

"(AA) the annual carbon intensity of the generator, as determined in accordance with subsection (g), expressed in metric tons per megawatt-hour; by

"(BB) 0.82; and

"(ii) the product obtained by multiplying—

"(I) the number of megawatt-hours of electric energy generated by the system that are consumed onsite by the facility; and

"(II) the annual target for electric energy sold during a calendar year that is required to be clean energy under subsection (c)(2).

"(B) ADDITIONAL CREDITS.—In addition to credits issued under subparagraph (A), the Secretary shall award clean energy credits to an owner of a qualified heat and power system in the United States for greenhouse gas emissions avoided as a result of the use of a qualified combined heat and power system, rather than a separate thermal source, to meet onsite thermal needs.

"(4) QUALIFIED WASTE-TO-ENERGY.—The quantity of clean energy credits issued to an electric utility generating electric energy in the United States from a qualified waste-to-energy facility shall be equal to the product obtained by multiplying—

"(A) the number of megawatt-hours of electric energy generated by the facility and sold by the utility; and

"(B) 1.0.

"(g) DETERMINATION OF ANNUAL CARBON INTENSITY OF GENERATING FACILITIES.—

"(1) IN GENERAL.—For purposes of determining the quantity of credits under subsection (f), except as provided in paragraph (2), the Secretary shall determine the annual carbon intensity of each generator by dividing—

"(A) the net annual carbon dioxide equivalent emissions of the generator; by

"(B) the annual quantity of electricity generated by the generator.

"(2) BIOMASS.—The Secretary shall—

"(A) not later than 180 days after the date of enactment of this section, issue interim regulations for determining the carbon intensity based on an initial consideration of the issues to be reported on under subparagraph (B);

"(B) not later than 180 days after the date of enactment of this section, enter into an agreement with the National Academy of Sciences under which the Academy shall—

"(i) evaluate models and methodologies for quantifying net changes in greenhouse gas emissions associated with generating electric energy from each significant source of qualified renewable biomass, including evaluation of additional sequestration or emissions associated with changes in land use by the production of the biomass; and

"(ii) not later than 1 year after the date of enactment of this section, publish a report that includes—

"(I) a description of the evaluation required by clause (i); and

"(II) recommendations for determining the carbon intensity of electric energy generated from qualified renewable biomass under this section; and

"(C) not later than 180 days after the publication of the report under subparagraph (B)(ii), issue regulations for determining the carbon intensity of electric energy generated from qualified renewable biomass that take into account the report.

"(3) CONSULTATION.—The Secretary shall consult with—

"(A) the Administrator of the Environmental Protection Agency in determining the annual carbon intensity of generating facilities under paragraph (1); and

"(B) the Administrator of the Environmental Protection Agency, the Secretary of the Interior, and the Secretary of Agriculture in issuing regulations for determining the carbon intensity of electric energy generated by biomass under paragraph (2)(C).

"(h) CIVIL PENALTIES.—

"(1) IN GENERAL.—Subject to paragraph (2), an electric utility that fails to meet the requirements of this section shall be subject to a civil penalty in an amount equal to the product obtained by multiplying—

"(A) the number of kilowatt-hours of electric energy sold by the utility to electric consumers in violation of subsection (c); and

"(B) 200 percent of the value of the alternative compliance payment, as adjusted under subsection (m).

"(2) WAIVERS AND MITIGATION.—

"(A) FORCE MAJEURE.—The Secretary may mitigate or waive a civil penalty under this subsection if the electric utility was unable to comply with an applicable requirement of this section for reasons outside of the reasonable control of the utility.

"(B) REDUCTION FOR STATE PENALTIES.—The Secretary shall reduce the amount of a penalty determined under paragraph (1) by the amount paid by the electric utility to a State for failure to comply with the requirement of a State renewable energy program, if the State requirement is more stringent than the applicable requirement of this section.

"(3) PROCEDURE FOR ASSESSING PENALTY.—The Secretary shall assess a civil penalty under this subsection in accordance with section 333(d) of the Energy Policy and Conservation Act (42 U.S.C. 6303(d)).

"(i) ALTERNATIVE COMPLIANCE PAYMENTS.—An electric utility may satisfy the requirements of subsection (c), in whole or in part, by submitting in lieu of a clean energy credit issued under this section a payment equal to the amount required under subsection (d)(2), in accordance with such regulations as the Secretary may promulgate.

"(j) STATE ENERGY EFFICIENCY FUNDING PROGRAM.—

"(1) ESTABLISHMENT.—Not later than December 31, 2015, the Secretary shall establish a State energy efficiency funding program.

"(2) FUNDING.—All funds collected by the Secretary as alternative compliance payments under subsection (i), or as civil penalties under subsection (h), shall be used solely to carry out the program under this subsection.

"(3) DISTRIBUTION TO STATES.—

"(A) IN GENERAL.—An amount equal to 75 percent of the funds described in paragraph (2) shall be used by the Secretary, without further appropriation or fiscal year limitation, to provide funds to States for the implementation of State energy efficiency plans under section 362 of the Energy Policy and Conservation Act (42 U.S.C. 6322), in accordance with the proportion of those amounts collected by the Secretary from each State.

"(B) ACTION BY STATES.—A State that receives funds under this paragraph shall maintain such records and evidence of compliance as the Secretary may require.

"(4) GUIDELINES AND CRITERIA.—The Secretary may issue such additional guidelines and criteria for the program under this subsection as the Secretary determines to be appropriate.

"(k) EXEMPTIONS.—

"(1) IN GENERAL.—This section shall not apply during any calendar year to an electric utility that sold less than the applicable quantity described in paragraph (2) of megawatt-hours of electric energy to electric consumers during the preceding calendar year.

"(2) APPLICABLE QUANTITY.—For purposes of paragraph (1), the applicable quantity is—

"(A) in the case of calendar year 2015, 2,000,000;

"(B) in the case of calendar year 2016, 1,900,000;

"(C) in the case of calendar year 2017, 1,800,000;

"(D) in the case of calendar year 2018, 1,700,000;

"(E) in the case of calendar year 2019, 1,600,000;

"(F) in the case of calendar year 2020, 1,500,000;

"(G) in the case of calendar year 2021, 1,400,000;

"(H) in the case of calendar year 2022, 1,300,000;

"(I) in the case of calendar year 2023, 1,200,000;

"(J) in the case of calendar year 2024, 1,100,000; and

"(K) in the case of calendar year 2025 and each calendar year thereafter, 1,000,000.

"(3) CALCULATION OF ELECTRIC ENERGY SOLD.—

"(A) DEFINITIONS.—In this subsection, the terms 'affiliate' and 'associate company' have the meanings given the terms in section 1262 of the Energy Policy Act of 2005 (42 U.S.C. 16451).

"(B) INCLUSION.—For purposes of calculating the quantity of electric energy sold by an electric utility under this subsection, the quantity of electric energy sold by an affiliate of the electric utility or an associate company shall be treated as sold by the electric utility.

"(l) STATE PROGRAMS.—

"(1) SAVINGS PROVISION.—

"(A) IN GENERAL.—Subject to paragraph (2), nothing in this section affects the authority of a State or a political subdivision of a State to adopt or enforce any law or regulation relating to—

"(i) clean or renewable energy; or

"(ii) the regulation of an electric utility.

"(B) FEDERAL LAW.—No law or regulation of a State or a political subdivision of a

State may relieve an electric utility from compliance with an applicable requirement of this section.

"(2) COORDINATION.—The Secretary, in consultation with States that have clean and renewable energy programs in effect, shall facilitate, to the maximum extent practicable, coordination between the Federal clean energy program under this section and the relevant State clean and renewable energy programs.

"(m) ADJUSTMENT OF ALTERNATIVE COMPLIANCE PAYMENT.—Not later than December 31, 2016, and annually thereafter, the Secretary shall—

"(1) increase by 5 percent the rate of the alternative compliance payment under subsection (d)(2); and

"(2) additionally adjust that rate for inflation, as the Secretary determines to be necessary.

"(n) REPORT ON CLEAN ENERGY RESOURCES THAT DO NOT GENERATE ELECTRIC ENERGY.—

"(1) IN GENERAL.—Not later than 3 years after the date of enactment of this section, the Secretary shall submit to Congress a report examining mechanisms to supplement the standard under this section by addressing clean energy resources that do not generate electric energy but that may substantially reduce electric energy loads, including energy efficiency, biomass converted to thermal energy, geothermal energy collected using heat pumps, thermal energy delivered through district heating systems, and waste heat used as industrial process heat.

"(2) POTENTIAL INTEGRATION.—The report under paragraph (1) shall examine the benefits and challenges of integrating the additional clean energy resources into the standard established by this section, including—

"(A) the extent to which such an integration would achieve the purposes of this section;

"(B) the manner in which a baseline describing the use of the resources could be developed that would ensure that only incremental action that increased the use of the resources received credit; and

"(C) the challenges of pricing the resources in a comparable manner between organized markets and vertically integrated markets, including options for the pricing.

"(3) COMPLEMENTARY POLICIES.—The report under paragraph (1) shall examine the benefits and challenges of using complementary policies or standards, other than the standard established under this section, to provide effective incentives for using the additional clean energy resources.

"(4) LEGISLATIVE RECOMMENDATIONS.—As part of the report under paragraph (1), the Secretary may provide legislative recommendations for changes to the standard established under this section or new complementary policies that would provide effective incentives for using the additional clean energy resources.

"(o) EXCLUSIONS.—This section does not apply to an electric utility located in the State of Alaska or Hawaii.

"(p) REGULATIONS.—Not later than 1 year after the date of enactment of this section, the Secretary shall promulgate regulations to implement this section.

"SEC. 611. REPORT ON NATURAL GAS CONSERVATION.

"Not later than 2 years after the date of enactment of this section, the Secretary shall submit to Congress a report that—

"(1) quantifies the losses of natural gas during the production and transportation of the natural gas; and

"(2) makes recommendations, as appropriate, for programs and policies to promote conservation of natural gas for beneficial use.".

EXHIBIT ____

U.S. Energy Information Administration

Analysis of Impacts of a Clean Energy Standard

as requested by Chairman Bingaman

November 2011

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

SC EXHIBIT 26

Contacts

This report, *Analysis of Impacts of a Clean Energy Standard, as requested by Chairman Bingaman*, was prepared under the general guidance of John Conti, Assistant Administrator for Energy Analysis, J. Alan Beamon at 202/586-2025 (email, joseph.beamon@eia.gov), Director, Office of Electricity, Coal, Nuclear, and Renewable Analysis, and Robert Eynon at 202/586-2392 (email, robert.eynon@eia.gov), Leader, Renewable Analysis Team.

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Preface

This report addresses an August 2011 request to the U.S. Energy Information Administration (EIA) from Senator Jeff Bingaman, Chairman of the U.S. Senate Committee on Energy and Natural Resources, for an analysis of the impacts of a Clean Energy Standard (CES). The request, outlined in the initial letter and later amended (Appendix A), sets out specific assumptions and scenarios for the study.

Contents

Figures

Tables

Introduction

This report responds to a request from Senator Jeff Bingaman, Chairman of the U.S. Senate Committee on Energy and Natural Resources, for an analysis of a national Clean Energy Standard (CES). The request, as outlined in the letter included in Appendix A, sets out specific policy assumptions for the study.

Background

A CES is a policy that requires covered electricity retailers to supply a specified share of their electricity sales from qualifying clean energy resources. Under a CES, electric generators would be granted clean energy credits for every megawatthour (MWh) of electricity they produce using qualifying clean energy sources. Utilities that serve retail customers would use some combination of credits granted to their own generation or credits acquired in trade from other generators to meet their CES obligations. Generators without retail customers or utilities that generated more clean energy credits than needed to meet their own obligations could sell CES credits to other companies.

The design details of a CES can significantly affect its projected impacts. Chairman Bingaman's request sets out a base CES specification and several variants. The base CES specification, henceforth referred to as the Bingaman CES (BCES) case, has various provisions describing the definition of clean energy, the allocation of credits, and the dates when target milestones become binding, as described below:

- All generation from existing and new wind, solar, geothermal, biomass, municipal solid waste, and landfill gas plants earns full BCES credits.
- Incremental hydroelectric and nuclear generation from capacity uprates at existing plants and from new plants earns full BCES credits.
- Generation from existing nuclear and hydroelectric capacity does not receive any BCES credits. However, the total generation from these two sources counts towards the overall clean energy sales goal of the policy. Generation from these sources is reflected in the policy through a reduced requirement for holding BCES credits.
- Partial BCES credits are earned for generation using specific technologies fueled by natural gas or coal, based on a calculated crediting factor that reflects the carbon intensity of each technology relative to that of a new supercritical coal plant. These technologies include coal plants which capture and sequester their carbon dioxide emissions (0.9 BCES credits), natural gas plants that also sequester their carbon dioxide emissions (0.95 BCES credits), existing natural gas combined-cycle units (0.48 BCES credits), new gas combined-cycle units (0.59 BCES credits), existing gas combustion turbines (0.16 BCES credits), new gas combustion turbines (0.45 BCES credits), and integrated gasification combined-cycle (IGCC) coal plants without carbon capture (0.15 BCES credits).
- The BCES target for the share of retail electricity sales from clean energy sources starts at 45 percent in 2015 and ultimately reaches 95 percent in 2050. However, as noted above, the requirement to hold BCES credits is generally reduced by generation from existing nuclear and hydroelectric capacity, which counts toward the clean energy targets but does not earn BCES credits.

  Table 1 below shows both the overall BCES case clean energy targets and the estimated requirement for covering sales with BCES credits given projected generation from existing nuclear and hydroelectric capacity. For example, in the Reference case[1] projection for 2035, these generation sources account for about 24 percent of sales, so the 80-percent clean energy goal requires that 56 percent (80 percent minus 24 percent) of sales be covered by BCES credits

- BCES clean energy goals increase linearly between the milestones shown in Table 1, with a 2-percentage point annual increase between 2020 and 2035 and a 1-percentage point annual increase in the first 5 years of the BCES and between 2035 and 2050.
- There is no sunset date for the requirements, so the 95-percent clean energy goal remains in effect beyond 2050.
- All electricity providers are covered by the requirement, regardless of ownership type or size.
- BCES credits can be banked for use in a subsequent year. There is no limit on how many credits may be held or for how long they may be held.
- The BCES operates independently of any State-level policies. The same underlying generation can be used to simultaneously comply with the BCES and any State generation requirements, if otherwise allowed for by both Federal and State law.

Table 1. BCES Clean Energy Goals and Credit Coverage Requirements

Year	Overall Clean-Energy Goal	Percentage of Total Sales that Must be Covered by BCES Credits
2015	45%	17%
2020	50%	23%
2025	60%	34%
2030	70%	45%
2035	80%	56%
2040	85%	62%
2045	90%	68%
2050	95%	74%

Like other EIA analyses of energy and environmental policy proposals, this report focuses on the impacts of those proposals on energy choices in all sectors and the implications of those decisions for emissions and the economy. This focus is consistent with EIA's statutory mission and expertise. The study does not account for any possible health or environmental benefits that might be associated with the BCES policy.

Alternative Cases

As noted above, Chairman Bingaman also requested that several variations of the base CES specification be analyzed. The first three cases listed, the All Clean, Partial Credit, and Revised Baseline cases, examine several alternative treatments for existing nuclear and hydroelectric generation facilities, giving them either a partial or a full credit for generation. The Partial Credit case also includes an alternative treatment for the crediting of qualifying fossil generation.

[1] The reference case in this report includes some revisions to the *AEO2011* Reference case. The primary changes include an improved representation of interregional capacity transfers for reliability pricing and reserve margins. Also, capacity expansion decisions incorporate better foresight of future capital cost trends by including expectations of the commodity price index.

All Clean case (AC): Generation from existing nuclear and hydroelectric capacity receives full credit. As indicated in Table 2, in this case, the requirement to hold BCES credits is equivalent to the overall clean energy goal.

Partial Credit case (PC): Generation from all natural gas combined-cycle units without carbon capture equipment receives one-half credit. Gas combustion turbines and coal plants without carbon capture do not receive credit. However, generation from existing nuclear and hydroelectric plants each receive one-tenth of a credit, which provides an added incentive to continue operating existing capacity of these types relative to the BCES case. As shown in Table 2, the requirements to hold BCES credits are adjusted from the BCES case to account for the differing crediting scheme and to maintain the overall goal for clean energy generation.

Revised Baseline case (RB): Electricity service providers may subtract generation from existing nuclear and hydroelectric capacity from their sales baseline when calculating their clean energy requirement. Although the requirement for covering sales with BCES credits shown in Table 2 differs slightly from the requirements in the BCES case, this case is meant to achieve the same overall goal for clean energy use. Removing generation from existing nuclear and hydroelectric facilities from the sales baseline and adjusting the target to compensate for this change provides an incentive to continue operating existing nuclear and hydroelectric facilities.

The next four cases potentially reduce the amount of clean energy stimulated by the CES, either by exempting small electricity suppliers from meeting the target ("Small Utilities Exempt"), capping the maximum credit price paid by suppliers ("Credit Cap 2.1" and "Credit Cap 3.0"), or decreasing total electricity demand through increased efficiency standards ("Standards and Codes").

Small Utilities Exempt case (SUE): Electricity suppliers with annual sales lower than 4 million MWh are exempt from the clean energy requirements. They may produce and sell BCES credits, but they do not need to hold them. As with the Revised Baseline case, the effective sales basis is reduced in this case relative to the BCES case; however, unlike the BCES case, there is no adjustment to the mandatory target applied to each affected utility. As shown in Table 2, the clean energy target as a percent of covered sales in the SUE case is the same as in the BCES case. However, as a percent of total sales, the CES in the SUE case is less stringent than in the BCES case.

Credit Cap 2.1 case (C2.1): The price of BCES credits is effectively capped through the availability of unlimited alternative compliance credits starting at a price of 2.1 cents per kilowatthour in 2015 and rising 5 percent per year above the rate of inflation each year thereafter. Although neither the goal nor the mandatory targets is changed in this case from the BCES case, the amount of clean energy generation achieved may be less than the indicated goal/target to the extent that alternative compliance credits are used for compliance in lieu of credits from actual clean energy generation.

Credit Cap 3.0 case (C3.0): Unlimited alternative compliance credits are made available starting at a price of 3.0 cents per kilowatthour in 2015 and rising 5 percent per year above the rate of inflation each year thereafter. Although neither the goal nor the mandatory targets are changed in this case from the BCES case, the amount of clean energy generation achieved may be less than the indicated goal/target to the extent that alternative compliance credits are used for compliance in lieu of credits from actual clean energy generation.

Standards and Codes case (S+C): Adds additional rounds of efficiency standards for currently covered products as well as new standards for products not yet covered. Efficiency levels assume improvement similar to those in *Energy Star* or Federal Energy Management Plan (FEMP) guidelines. The Standards and Codes case corresponds to the Expanded Standards and Codes case that was part of *AEO2011*. More information about the assumptions underlying this case can be found in Appendix E of the *AEO2011*.

With the exception of the SUE case, all of the alternative cases described above share the goal in the BCES case of covering 80 percent of total national sales with generation from clean energy by 2035. However, the number of credits required in each case varies because of differences in the sales baselines and the number of credits assigned to different technologies, particularly with respect to the treatment of generation from existing hydroelectric facilities and nuclear plants (Table 2). In the BCES, AC and PC cases all sales are covered by the credit program. In the RB case, covered sales are reduced by the generation from existing hydroelectric and nuclear plants and, in the SUE case, they are reduced by sales from small utilities.

Focusing on 2035, in the BCES case 56 percent of total sales must be covered by credits. As described above, the credit share required in the BCES case is below the 80 percent clean energy goal because projected generation coming from existing hydroelectric and nuclear plants does not earn credits but still counts towards the overall clean energy goal. In the AC case, the share of sales that must be covered by credits equals the overall clean energy goal because all generation from hydroelectric and nuclear plants, whether existing or new, earn credits. In the PC and RB cases, the share of total sales that must be covered by credits is very similar to that in the BCES case. The shares are slightly higher in the PC case because generation from existing hydroelectric and nuclear plants earns a small share of credits in this case. In the SUE case, the share of total sales that must hold credits is significantly lower than in the BCES case because sales from small utilities are not required to hold credits. These small utilities account for roughly 25 percent of sales so the overall credit share required is lower by about that amount.

Table 2. Clean Energy Goal and Credit Shares Across Select Cases[1]

Year	Overall Clean-Energy Goal[1]	Required Clean Energy Target as a Percent of All Sales					SUE as a Percent of Covered Sales
		BCES	AC	PC	RB	SUE	
2015	45%	17%	45%	20%	23%	12%	17%
2020	50%	23%	50%	26%	32%	17%	23%
2025	60%	34%	60%	37%	46%	25%	34%
2030	70%	45%	70%	48%	60%	34%	45%
2035	80%	56%	80%	58%	74%	42%	56%
2040	85%	62%	85%	64%	80%	46%	62%
2045	90%	68%	90%	70%	87%	50%	68%
2050	95%	74%	95%	76%	94%	54%	74%

[1] Goal is expressed as a percent of all sales, except for the Small Utilities Exempt (SUE) case, where it is expressed as a percent of covered sales, as specified in the modified request letter for this study (see Appendix A). In 2035, covered sales in the SUE case are about 75 percent of national sales, reducing the effective clean energy goal to about 60 percent of national sales. For the C2.1 and C3.0 cases, the realized clean energy coal may fall below the 80 percent national target due to the use of alternative compliance credits.

Results

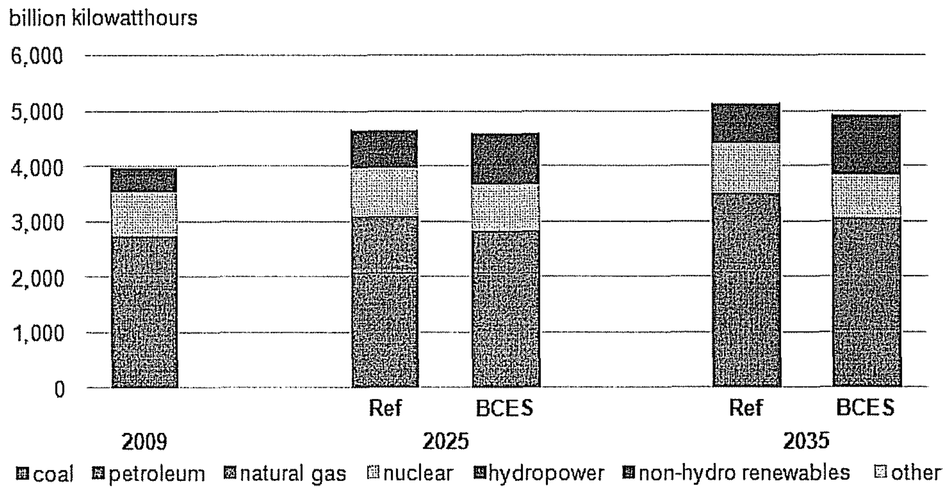
BCES case impacts relative to the *AEO2011* Reference case

The BCES policy changes the generation mix, reducing the role of coal technologies and increasing reliance on natural gas, non-hydro renewable and nuclear technologies (Figure 1, Tables B1 and B2). Coal-fired generation, which in the Reference case increases by 23 percent from 2009 to 2035, decreases by 41 percent in the BCES case over the same period. Relative to the Reference case, where natural gas generation grows steadily throughout the projection period, natural gas generation in 2025 is 34-percent higher and 53-percent higher in 2035. Under the BCES policy, non-hydro renewable technologies grow at the fastest rate, increasing from 146 billion kilowatthours in 2009 to 601 billion kilowatthours in 2025 and 737 billion kilowatthours in 2035. These totals are 60 percent and 75 percent greater than the 2025 and 2035 Reference case projections, respectively.

The BCES case provides different incentives to existing and new nuclear power plants because only the latter earn credits. Nearly 65 gigawatts of new capacity are installed by 2035 in the BCES case compared to approximately 6 gigawatts in the Reference case. Generation from existing nuclear plants does not qualify for credits and, as a result, more than 14 gigawatts of this capacity are taken out of service, while less than 2 gigawatts of capacity are retired in the Reference case.

Since fossil-fueled generation that captures and sequesters carbon emissions is given nearly full BCES credit, the BCES spurs 47 gigawatts of coal capacity to be retrofitted with carbon capture and sequestration (CCS) equipment by 2035. Nearly all of these retrofits occur in the final 10 years of the forecast period, with less than one gigawatt of capacity retrofitted by 2025. No new coal plants with CCS are added in the BCES case beyond the small amount found in the Reference case.

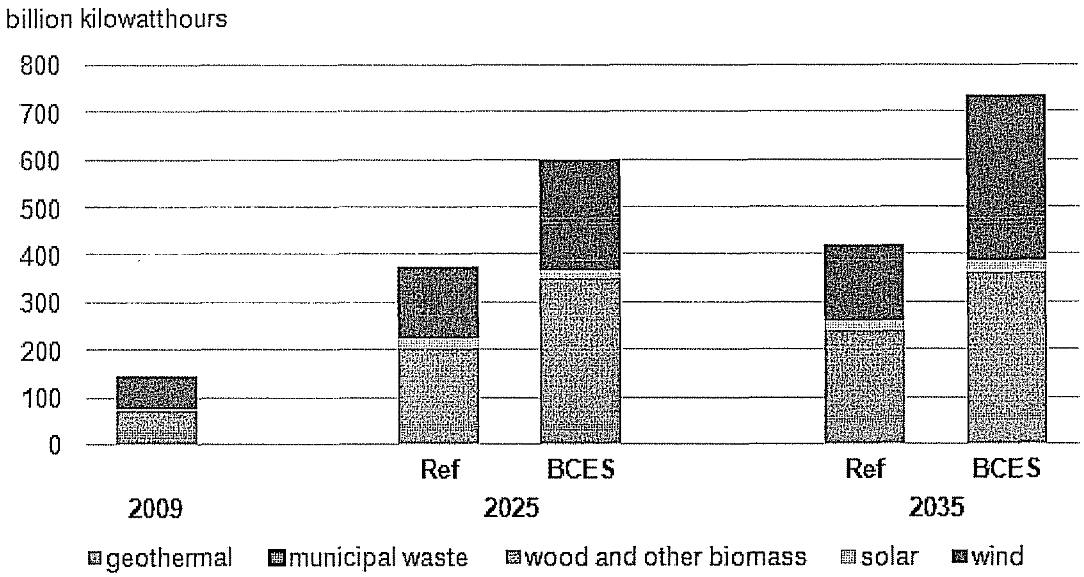
Figure 1. Total Net Electricity Generation



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

Among renewable sources, wind and biomass have the largest generation increases under the BCES (Figure 2, Tables B1 and B2). Under the BCES policy, 2035 wind generation is more than five times its 2009 level. Total 2035 wind generation under the BCES is more than double the 2035 level in the Reference case. Biomass generation shows robust growth, as well, within the BCES framework. All of the growth in biomass use relative to the Reference case is attributable to co-fired generation, which reaches 187 billion kilowatthours in 2025 before declining to 156 billion kilowatthours in 2035 as coal-fired plants that co-fire biomass are retired.

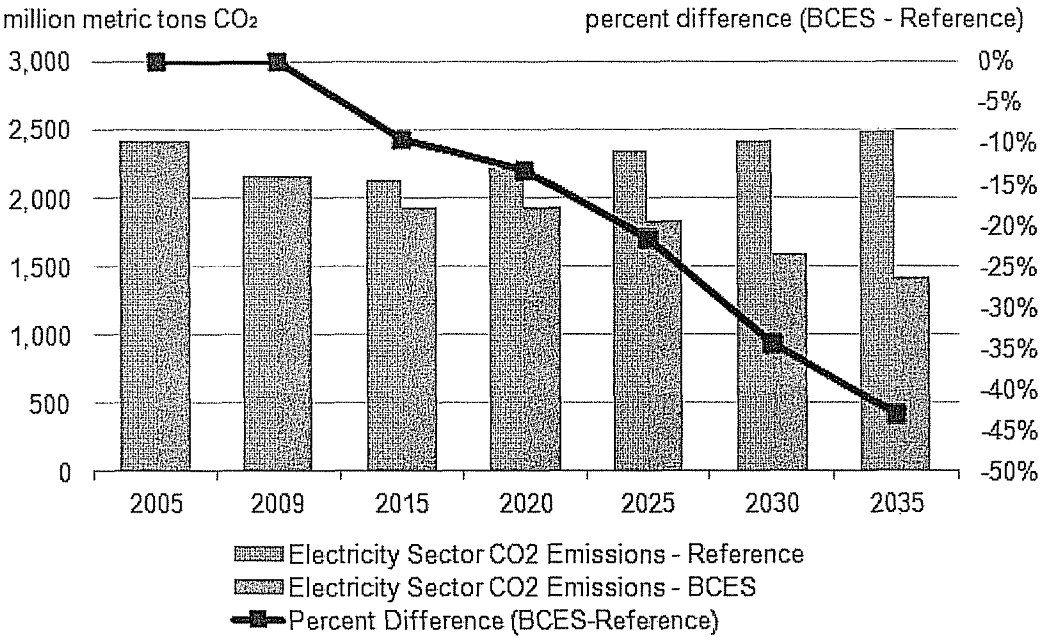
Figure 2. Total Non-Hydroelectric Renewable Generation



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

Under the BCES, projected annual electricity sector carbon dioxide emissions are 22 percent below the Reference case level in 2025 and 43 percent lower in 2035 (Figure 3, Tables B1 and B2). In the Reference case electricity-sector carbon dioxide emissions increase modestly over the projection period, reaching annual emissions of 2,345 million metric tons of carbon dioxide (MMTCO2) in 2025 and growing further to 2,500 MMTCO2 emitted in 2035. Over the 2009-to-2035 period, cumulative CO_2 emissions are 20 percent lower in the BCES case than they are in the Reference case.

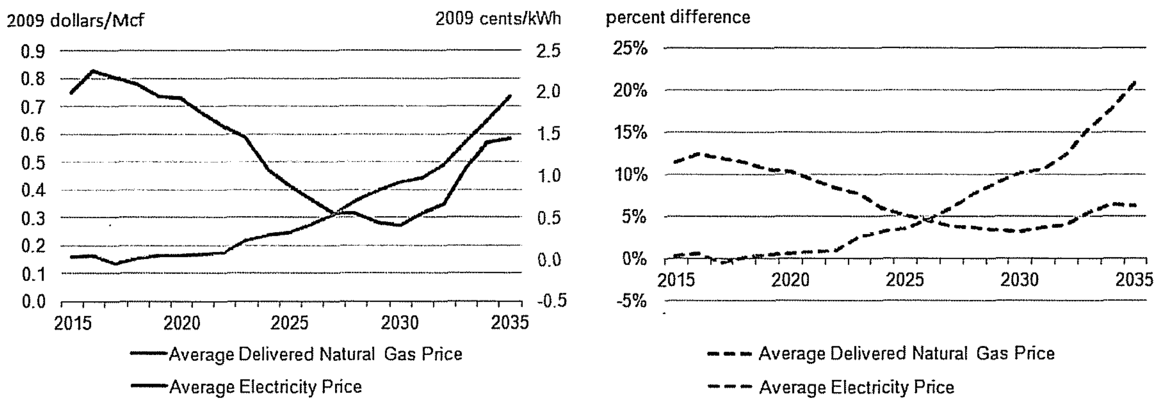
Figure 3. Electricity Sector Carbon Dioxide Emissions



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

The BCES has a negligible impact on electricity prices through 2022, but prices rise in later years. (Figure 4, Tables B1 and B2). In the early years of the projection period, there is negligible impact on average end-use electricity prices, as the requirement to hold BCES credits is modest. As shown in Table 1, the share of total sales that must be covered by credits does not exceed 45 percent until after 2030. This is important because, while coal-fired plants do not receive BCES credits, efficient combined cycle plants receive 0.48 credits for each megawatthour they generate, more than retailers purchasing their output are required to hold until after 2030. This effectively reduces the cost of most natural gas-fired generation until the later years of the projections. Electricity prices do grow later in the projections, reaching 21 percent above the Reference case level by 2035 in the BCES case.

Figure 4. BCES Impact on Electricity and Natural Gas Prices (BCES Difference from Reference case)



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

While average end-use electricity prices increase nationally after 2020 in the BCES case, the increase is not the same across all regions (Table 3). In 2025, when national average electricity prices in the BCES case are projected to be 3.6 percent above the Reference case level, regional projected prices are below the Reference case level in 8 of the 22 regions including New England (NEWE) and California (CAMX) which already have significant generation from eligible clean energy resources. By 2035, prices are below the Reference case level in only one region, MRO East (MROE), reflecting the significant share of qualified end-use generation projected to be co-produced in that region by facilities producing cellulosic biofuels to comply with the Federal Renewable Fuels Standard. The regions with the highest price increases in 2035 (by percent) are the SERC Central Region (SRCE) (69.2-percent increase) and the WECC Northwest Region (NWPP) (61.5-percent increase). The two regions with the highest increases in terms of cents per kilowatthour in 2035 are NPCC Long Island (NYLI), where prices increase by 5.2 cents/kWh and SERC Central (SRCE), where prices increase by 4.2 cents/kWh.

Natural gas prices also increase in the BCES case, particularly in the early years of the projections (Figure 4, Tables B1 and B2). Early in the projection, natural gas prices rise as generation from natural gas increases to comply with the BCES and bank credits for future use. As new capacity is built and other clean technologies continue to be expanded, the natural gas price premium over the Reference case gradually declines. Natural gas price impacts reach their height in 2016, where prices are $0.83/ thousand cubic feet (12 percent) higher than in the Reference case.

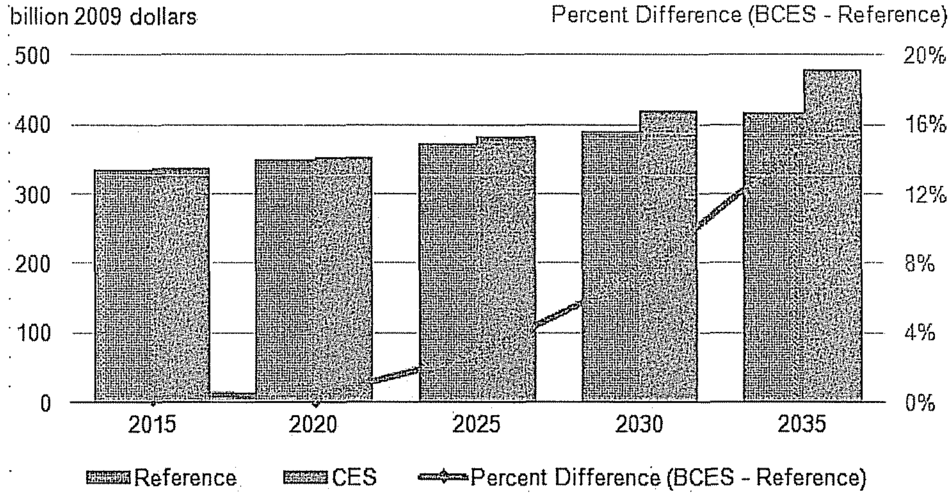
Table 3. BCES Regional End-use Sector Average Prices (2009 cents/kWh)

Region	2009	2025		2035	
		Reference	BCES	Reference	BCES
ERCT - ERCOT All	10.4	9.2	9.0	10.0	11.6
FRCC - FRCC All	11.6	10.9	12.0	11.2	13.6
MROE - MRO East	9.3	7.5	7.0	7.3	5.9
MROW - MRO West	7.6	6.8	8.0	6.9	8.9
NEWE - NPCC New England	15.7	13.6	12.2	13.1	14.3
NYCW - NPCC NYC/Westchester	19.9	16.8	16.7	16.9	19.6
NYLI - NPCC Long Island	18.1	16.7	17.4	16.6	21.8
NYUP - NPCC Upstate NY	11.6	11.9	11.1	12.6	14.4
RFCE - RFC East	12.2	10.7	11.7	10.9	12.4
RFCM - RFC Michigan	9.6	8.7	9.0	9.0	11.4
RFCW - RFC West	8.6	8.5	8.5	9.9	11.0
SRDA - SERC Delta	7.5	7.3	7.2	7.5	9.7
SRGW - SERC Gateway	7.8	6.5	6.7	7.0	9.6
SRSE - SERC Southeastern	9.1	8.7	8.9	8.5	10.3
SRCE - SERC Central	7.8	6.0	7.2	6.0	10.2
SRVC - SERC VACAR	8.6	8.1	9.1	8.3	11.2
SPNO - SPP North	7.9	7.6	8.9	7.5	8.9
SPSO - SPP South	6.9	7.8	8.0	8.5	10.4
AZNM - WECC Southwest	9.8	9.5	9.5	10.4	11.3
CAMX - WECC California	13.3	14.6	13.1	13.2	14.0
NWPP - WECC Northwest	7.0	4.6	6.4	5.2	8.4
RMPA - WECC Rockies	8.2	9.0	9.4	9.4	11.1
U.S. Average	9.8	9.0	9.4	9.4	11.3

BCES electricity price is 10-25 percent greater than the Reference case electricity price
BCES electricity price is 25 percent or more greater than the Reference case electricity price
Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.
Note: See Appendix C for a map of the NEMS electricity market module regions.

Electricity expenditures increase in the BCES case after 2020 as a result of higher electricity prices (Figure 5, Tables B1 and B2). However, because electricity sales decrease later in the forecast period relative to the Reference case, the impact on electricity expenditures is smaller than the impact on electricity prices. In 2025 and 2035, total annual electricity expenditures across all sectors in the BCES case are 2.8 percent and 15.1 percent above the projected Reference case level, respectively. Household average annual electricity expenditures similarly increase over the projection horizon. In 2025, average household electricity expenditures are $1,198 in the BCES case – $36 above the Reference case. This difference increases to $170 in 2035 between the two cases ($1,366 versus $1,196).

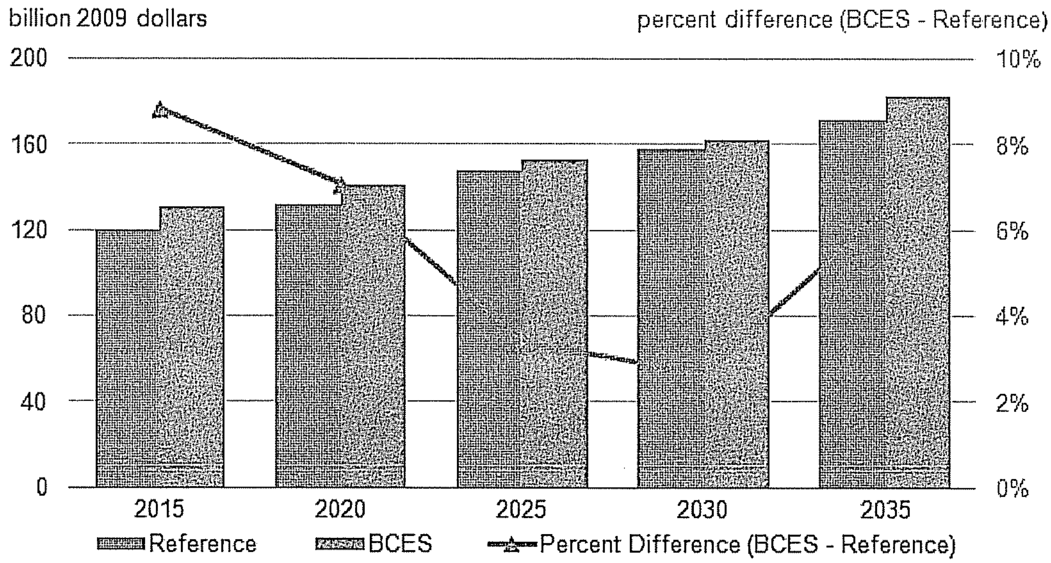
Figure 5. Total Electricity Expenditures



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

Higher natural gas prices also lead to increased natural gas expenditures outside the electricity sector in the BCES case (Figure 6, Tables B1 and B2). In 2025, non-electric natural gas expenditures in the BCES case are 3.4 percent higher than Reference case levels. This differential increases to 6.5 percent by 2035. Natural gas expenditures in the electric power sector experience upward pressure from both higher prices and higher consumption, but the impact of those changes on ultimate consumers is reflected in their electricity expenditures.

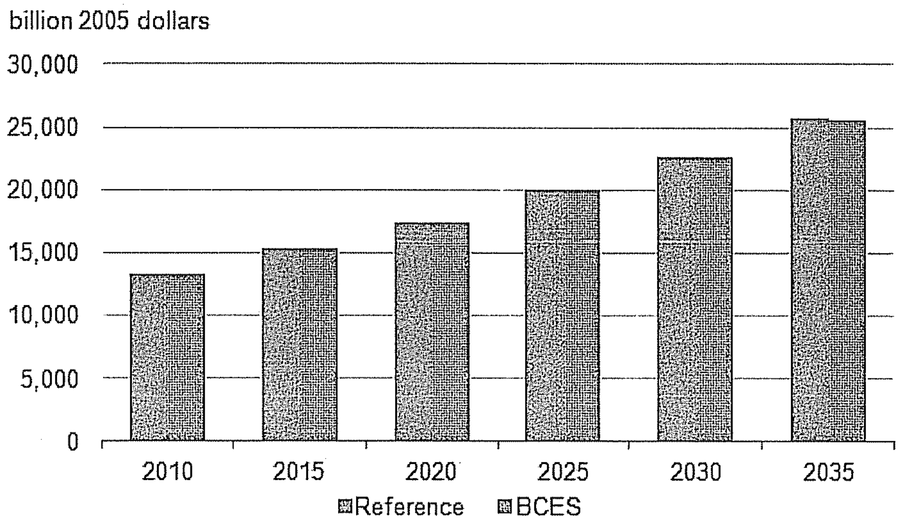
Figure 6. Natural Gas Expenditures, Not Including the Electric Power Sector



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

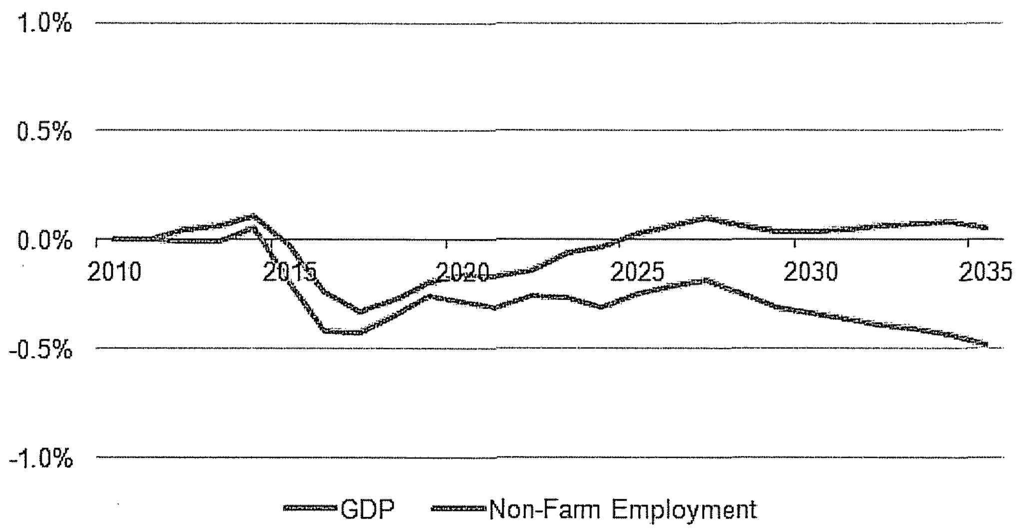
The BCES case reduces projected real Gross Domestic Product (GDP) relative to the Reference case, with a peak difference in the GDP level of less than half of one percent in 2035 and generally lower impact in earlier years. (Figures 7 and 8, Tables B1 and B2). GDP grows at an average annual rate of 2.67 percent between 2009 and 2035 in the BCES case, just slightly below the Reference case growth rate of 2.69 percent.

Figure 7. Annual Gross Domestic Product



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

Figure 8. BCES Impact on Employment and Real GDP, Percent Difference (BCES Difference from Reference case)



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b and cesbingbk.d100611a.

Alternative Case Results

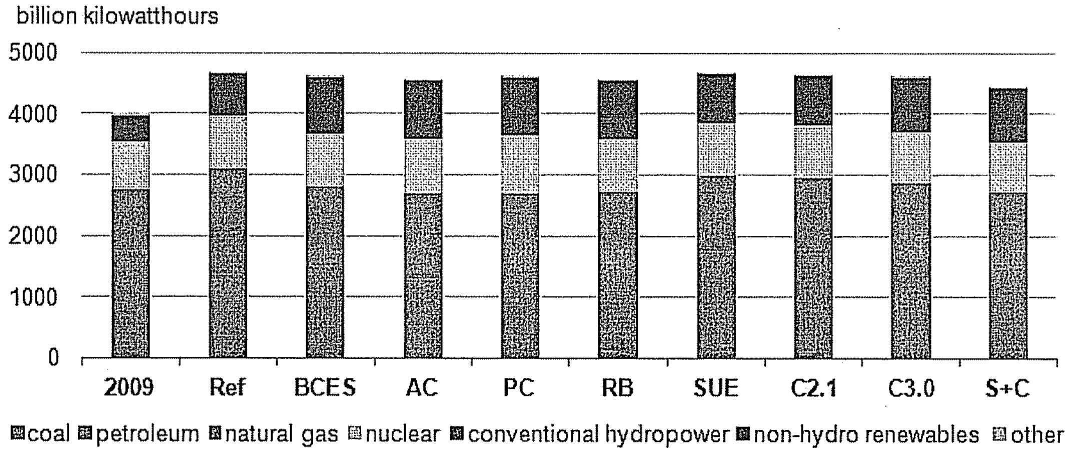
As described earlier, EIA also prepared alternative cases that vary certain aspects of the CES policy. This section briefly describes the main impacts of these alternative cases.

As in the BCES case, each of the alternative cases shows reductions in coal generation and increases in natural gas, renewable and nuclear generation (Figures 9 and 10). Because each of the alternative cases maintains the basic structure of giving renewable generation a full credit and no credits to conventional coal generation, all of the cases show renewable electricity generation growth relative to the Reference case. Natural gas and nuclear generation levels vary across the cases. The All Clean (AC), Partial Credit (PC) and Revised Baseline (RB) cases all show greater nuclear generation than in the BCES case. Each of these cases contains provisions aimed at providing some credit to existing nuclear plants which results in greater nuclear generation and lower coal generation. The highest nuclear generation occurs in the PC case where it reaches levels 9.7 percent and 62.2 percent greater than the BCES case in 2025 and 2035, respectively. This generation is 8.2 percent and 46.3 percent above the Reference case levels in those same years.

The shift away from coal is smaller in the cases with credit price caps, as compliance is achieved by making alternative compliance payments. This is particularly true in the Credit Cap 2.1 (C2.1) case where renewable generation is the smallest among alternative cases. Both this case and the Small Utilities Exempt (SUE) case, where suppliers with sales of less than four million MWhs are exempt from meeting the targets, have the largest coal generation as a result of the ability to comply without needing as much clean generation. The role played by fossil-fueled technologies that sequester carbon emissions varies across the cases, with larger amounts seen in the AC and RB cases that tend to have higher CES credit prices that spur the use of higher-cost technologies.

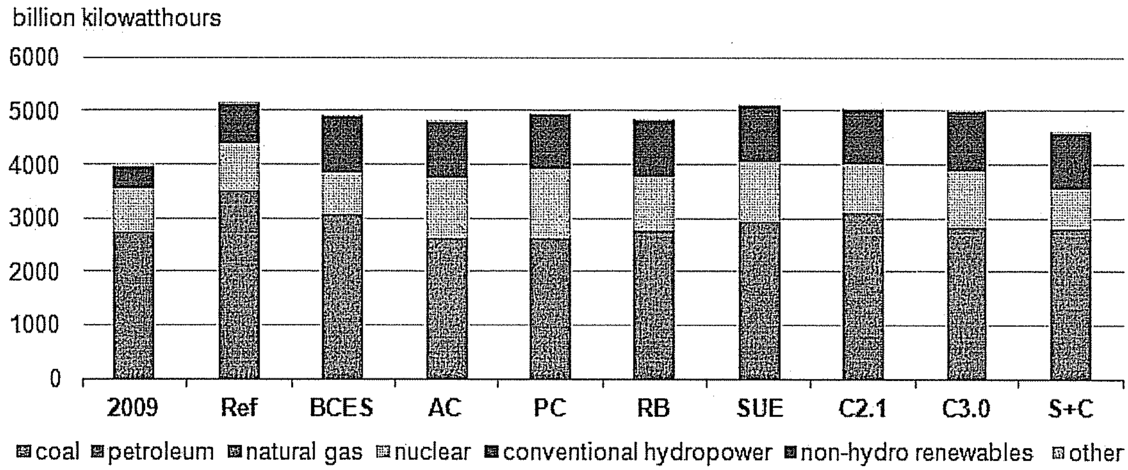
Non-hydroelectric renewable generation increases relative to the Reference case in all of the alternative cases, but it varies among them (Figures 11 and 12). The lowest level among the alternative cases in 2035 occurs in the C2.1 case where utilities rely on making alternative compliance payments rather than increasing clean generation, while the highest level occurs in the C3.0 case. In the C3.0 case, the option to make alternative compliance payments at a higher rate than in the C2.1 case results in coal generation between the levels in the BCES and C2.1 cases. However, the credit price levels in the C3.0 case are not high enough to support the high levels of new nuclear capacity seen in the other alternative cases, leading to a slightly higher level of non-hydro renewable generation than occurs in those cases.

Figure 9. Total Net Electricity Generation in Alternative Cases, 2025



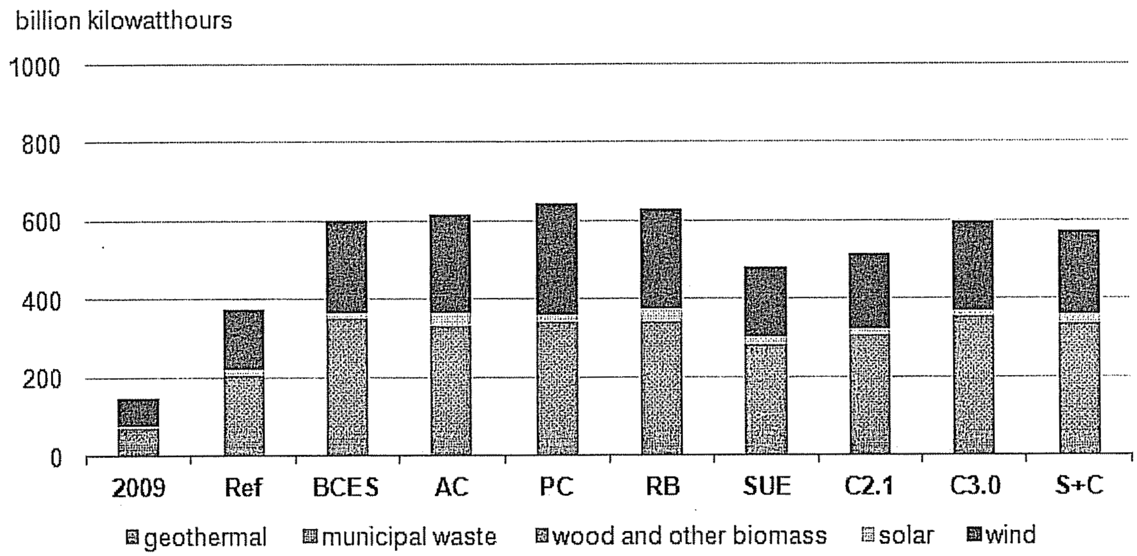
Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Figure 10: Total Net Electricity Generation in Alternative Cases, 2035



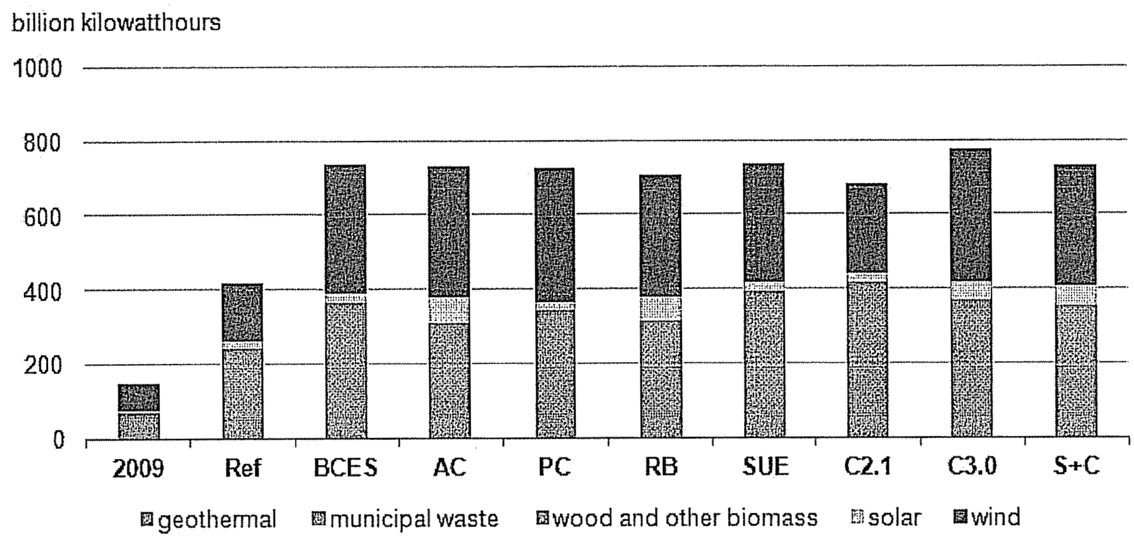
Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Figure 11. Total Non-hydroelectric Renewable Generation in Alternative Cases, 2025



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

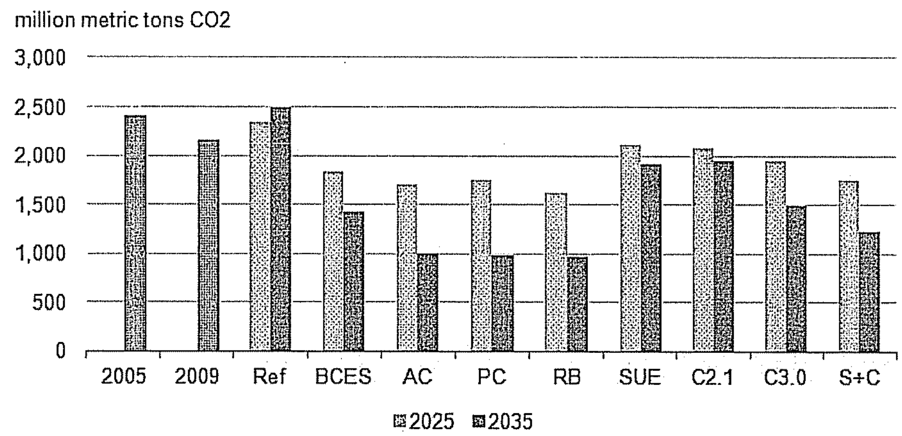
Figure 12. Total Non-hydroelectric Renewable Generation in Alternative Cases, 2035



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

While all alternative cases achieve carbon dioxide emissions reductions in the electric power sector relative to the Reference case, there are significant differences across cases (Figure 13). Trends in emissions directly reflect the generation mix. The cases with the largest emissions reductions, the RB, PC, and AC cases, achieve between 25 percent to 31 percent lower emissions in 2025 than in the Reference case. By 2035, their electricity sector carbon dioxide emissions fall to levels 60 percent to 63 percent below the Reference case, much larger than the 43 percent reduction seen in the BCES case. The larger emissions reductions in these cases occur because of incentives in them to continue operating existing nuclear plants while retiring additional coal plants. The opposite occurs in the SUE, C3.0, and C2.1 cases where the exclusion of small utilities from coverage or the credit price cap reduce the amount of clean energy needed for compliance.

Figure 13. Electric Power Sector Carbon Dioxide Emissions in Alternative Cases, 2025 and 2035

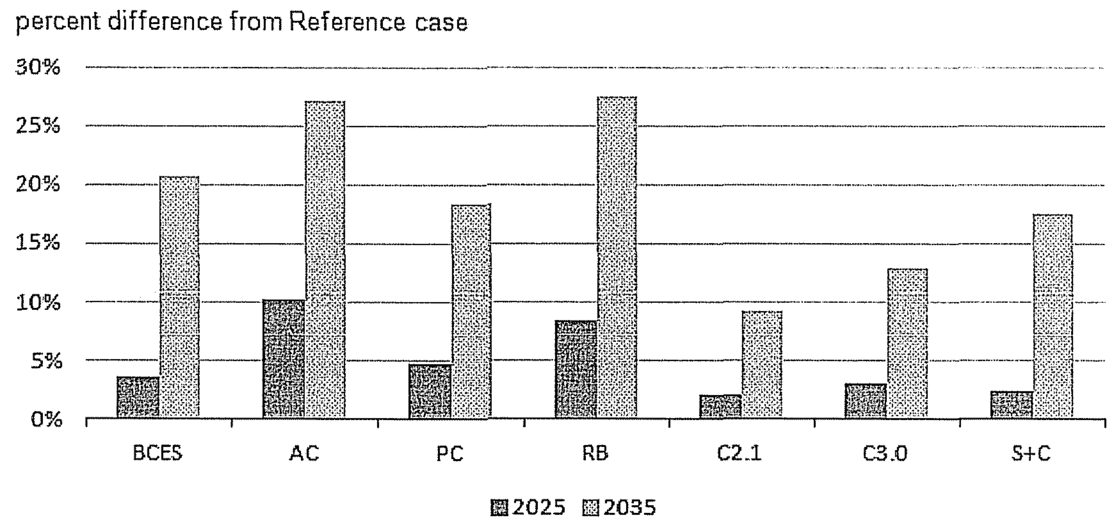


Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Each of the alternative cases causes average end-use electricity prices to rise relative to the Reference case by 2035, but there is a wide range of price changes (Figure 14). As in the BCES case, 2025 electricity price increases among the alternative cases are modest. The only case where 2025 electricity prices exceed Reference case prices by more than 10 percent is the AC case, where they are 10.3 percent higher. This occurs because the required credit share is much higher in the AC case, exceeding the credits given to natural gas combined cycle plants by 2018, much earlier than in the other cases. In contrast, the only case shown in Figure 14 to have a 2035 average electricity price that is not at least 10 percent above the Reference case projected price is the Credit Cap 2.1 case. Average 2035 electricity prices among all cases, however, are less than 30 percent higher than Reference case prices in that same year. The two cases with the highest percentage increases in 2035 prices are the Revised Baseline case and the All Clean case, each having prices that are approximately 27 percent higher than the Reference case. The electricity price in the Standards and Codes case does not reflect the higher level of expenditures needed for structures and equipment to meet more stringent codes and standards.

Electricity prices from the SUE case are not displayed in Figure 14, because EIA is not able to disaggregate the price impacts of exempt small utilities from those of larger covered utilities. Average price impacts in this case are subject to misinterpretation given that there is likely to be a considerable divergence in the price impacts on customers of exempt and non-exempt electricity providers. Price impacts in this case will vary depending on how the value of the credits earned by clean energy generators serving uncovered small utilities flows through to electricity prices. If the credits from these generators generally flow with the electricity to the small utilities they serve, the electricity prices to the customers of the exempt providers could actually fall because of revenue they earn selling the credits to non-exempt providers. However, the degree to which this might occur is uncertain.

Figure 14. Impacts on National Average Electricity Prices in Alternative Cases, 2025 and 2035



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Regional electricity prices also vary widely across cases (Tables 4 and 5). As with the national prices, the magnitude of the regional price impacts compared to the Reference case depends on the overall stringency of the targets and whether or not the compliance costs are capped. Generally, the largest price increases in percentage terms occur in regions where Reference case prices are relatively low (e.g. NWPP) or where prices are below the national average in regions that are heavily dependent on coal. As in the BCES case, prices in the MROE region decrease across all alternative cases by 2035. The All Clean and Standards and Codes cases cause the greatest number of regions (15 out of 22) to experience price increases of more than 25 percent in 2035. However, as noted in the discussion of the BCES case results, electricity expenditure impacts in the Standards and Codes case are ameliorated by lower levels of electricity use.

Table 4. Regional Average Electricity Prices in Alternative Cases, 2025 (2009 cents/kWh)

Region	2009	2025							
		Ref	BCES	AC	PC	RB	C2.1	C3.0	S+C
ERCT - ERCOT All	10.4	9.2	9.0	10.9	9.1	9.6	9.0	8.9	10.9
FRCC - FRCC All	11.6	10.9	12.0	12.7	12.0	12.1	11.3	11.4	12.7
MROE - MRO East	9.3	7.5	7.0	7.7	6.9	7.3	7.2	7.0	7.7
MROW - MRO West	7.6	6.8	8.0	7.9	8.1	8.0	7.4	7.4	7.9
NEWE - NPCC New England	15.7	13.6	12.2	14.6	12.5	13.7	13.3	12.8	14.6
NYCW - NPCC NYC/Westchestei	19.9	16.8	16.7	18.2	16.7	17.4	16.7	16.3	18.2
NYLI - NPCC Long Island	18.1	16.7	17.4	19.6	17.4	18.6	17.2	17.3	19.6
NYUP - NPCC Upstate NY	11.6	11.9	11.1	13.2	11.2	12.2	11.8	11.5	13.2
RFCE - RFC East	12.2	10.7	11.7	12.7	10.8	11.5	10.6	12.0	12.7
RFCM - RFC Michigan	9.6	8.7	9.0	9.9	9.1	9.3	9.1	8.9	9.9
RFCW - RFC West	8.6	8.5	8.5	10.1	9.5	9.7	8.9	8.9	10.1
SRDA - SERC Delta	7.5	7.3	7.2	6.5	7.0	7.1	7.2	7.2	6.5
SRGW - SERC Gateway	7.8	6.5	6.7	8.3	6.8	7.5	6.5	6.6	8.3
SRSE - SERC Southeastern	9.1	8.7	8.9	9.0	8.9	8.9	8.9	8.9	9.0
SRCE - SERC Central	7.8	6.0	7.2	6.7	7.3	7.1	6.8	7.1	6.7
SRVC - SERC VACAR	8.6	8.1	9.1	8.5	9.2	8.9	8.7	8.8	8.5
SPNO - SPP North	7.9	7.6	8.9	9.1	8.6	9.0	7.8	8.4	9.1
SPSO - SPP South	6.9	7.8	8.0	9.1	8.0	8.5	8.1	8.0	9.1
AZNM - WECC Southwest	9.8	9.5	9.5	9.8	10.0	9.8	9.7	9.6	9.8
CAMX - WECC California	13.3	14.6	13.1	13.2	13.1	13.2	13.2	13.1	13.2
NWPP - WECC Northwest	7.0	4.6	6.4	4.7	6.0	5.5	5.6	5.8	4.7
RMPA - WECC Rockies	8.2	9.0	9.4	11.0	9.9	10.2	9.2	9.3	11.0
U.S. Average	9.8	9.0	9.4	9.4	9.5	9.7	9.2	9.3	9.4

BCES/alternative case electricity price is 10-25 percent greater than the Reference case electricity price

BCES/alternative case electricity price is more than 25 percent above the Reference case electricity price

Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Table 5. Regional Average Electricity Prices in Alternative Cases, 2035 (2009 cents/kWh)

Region	2009	2035							
		Ref	BCES	AC	PC	RB	C2.1	C3.0	S+C
ERCT - ERCOT All	10.4	10.0	11.6	14.2	11.5	13.0	10.4	10.8	14.2
FRCC - FRCC All	11.6	11.2	13.6	14.6	13.5	14.3	12.7	13.0	14.6
MROE - MRO East	9.3	7.3	5.9	4.1	6.2	4.7	6.5	6.3	4.1
MROW - MRO West	7.6	6.9	8.9	8.8	9.3	9.1	8.6	8.8	8.8
NEWE - NPCC New England	15.7	13.1	14.3	16.7	13.1	15.5	12.5	12.6	16.7
NYCW - NPCC NYC/Westchestei	19.9	16.9	19.6	21.5	18.9	20.3	17.5	17.9	21.5
NYLI - NPCC Long Island	18.1	16.6	21.8	24.3	20.4	22.5	18.1	19.1	24.3
NYUP - NPCC Upstate NY	11.6	12.6	14.4	16.6	13.2	15.4	12.6	12.8	16.6
RFCE - RFC East	12.2	10.9	12.4	15.7	12.9	14.3	11.3	11.2	15.7
RFCM - RFC Michigan	9.6	9.0	11.4	10.7	10.6	11.5	10.0	10.4	10.7
RFCW - RFC West	8.6	9.9	11.0	13.1	11.0	12.6	10.0	10.2	13.1
SRDA - SERC Delta	7.5	7.5	9.7	7.4	8.2	8.1	8.1	8.6	7.4
SRGW - SERC Gateway	7.8	7.0	9.6	11.7	9.1	10.6	7.7	8.5	11.7
SRSE - SERC Southeastern	9.1	8.5	10.3	10.9	10.4	10.6	9.8	10.4	10.9
SRCE - SERC Central	7.8	6.0	10.2	8.2	9.6	9.4	8.1	8.9	8.2
SRVC - SERC VACAR	8.6	8.3	11.2	10.1	10.6	10.1	10.0	10.6	10.1
SPNO - SPP North	7.9	7.5	8.9	10.4	9.0	9.6	8.1	8.7	10.4
SPSO - SPP South	6.9	8.5	10.4	12.7	9.8	11.4	9.0	9.5	12.7
AZNM - WECC Southwest	9.8	10.4	11.3	11.5	11.4	11.1	11.2	11.4	11.5
CAMX - WECC California	13.3	13.2	14.0	13.2	14.0	13.3	13.2	13.5	13.2
NWPP - WECC Northwest	7.0	5.2	8.4	5.6	7.8	6.2	7.5	7.8	5.6
RMPA - WECC Rockies	8.2	9.4	11.1	12.6	11.7	12.1	10.4	11.0	12.6
U.S. Average	9.8	9.4	11.3	11.9	11.1	11.6	10.2	10.6	11.9

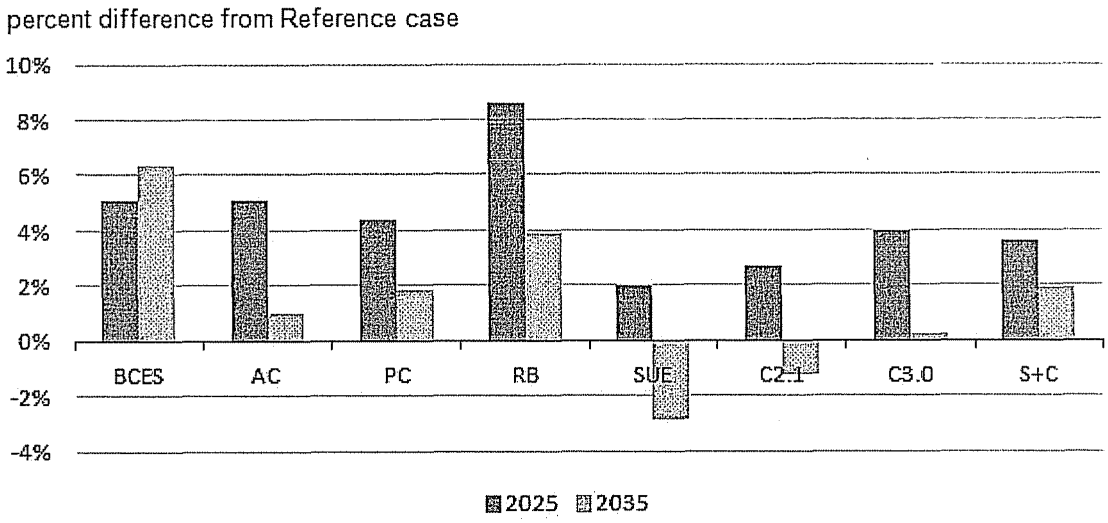
BCES/alternative case electricity price is 10-25 percent greater than the Reference case electricity price

BCES/alternative case electricity price is more than 25 percent above the Reference case electricity price

Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Natural gas price impacts are significant early in the projection period, but largely moderate by 2035 (Figure 15). In 2035, price impacts across cases are generally less than 5 percent, when compared to the Reference case. However, impacts on gas prices are generally more significant in the earlier years of the program. By 2025, impacts in three cases, All Clean, Revised Baseline, and Partial Credit, exceed 4 percent, with the Revised Baseline case exceeding 8 percent. Cases with reduced need for clean energy generation – the Small Utility Exemption case, the Standards and Codes case, and the two credit price cap cases – have more modest gas price impacts in the near-term. In 2025, only the Revised Baseline case, where natural gas generation in 2025 significantly exceeds the BCES case level, shows a larger impact on natural gas prices than the BCES case.

Figure 15. Impacts on Delivered Natural Gas Prices in Alternative Cases, 2025 and 2035



Source: U.S. Energy Information Administration. National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

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Appendix A: Request Letters

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

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August 16, 2011

Mr. Howard Gruenspecht
Acting Administrator
Energy Information Administration
1000 Independence Ave. SW
Washington, DC 20585

Dear Mr. Gruenspecht:

Over the past decade, Congress has considered many different legislative proposals to drive the development and deployment of clean generating technologies in the power sector and reduce the greenhouse gases resulting from the generation of electricity. During the current Congress I have focused my attention in this regard on a policy to establish a national Clean Energy Standard (CES) that would require an increasing percentage of electricity to be generated from clean sources. To this end, the Senate Committee on Energy and Natural Resources put forward a white paper seeking public input on the design of a CES. As the next step in the development of a legislative proposal, I am writing to request that you conduct an analysis of the effects of such a national Clean Energy Standard (CES) under a series of different scenarios.

The primary elements of the proposal to analyze should be as follows:

- The entities subject to the CES include all electric service providers that sell electricity to retail consumers. The base against which the clean requirement should be calculated is defined as all electric utility retail sales in a given calendar year.
- The yearly clean energy targets should ramp linearly from the current state of qualifying clean energy generation to an overall target of 80% clean energy in 2035 and holding at 80% indefinitely beyond 2035.
- Full or partial clean energy credits should be awarded to generators with a lower carbon-intensity (as measured on a carbon dioxide equivalency basis) than that of new supercritical coal generation ("new scrubbed coal plant" as defined in Table 8.2 of *Assumptions to the Annual Energy Outlook 2011*, *http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf*). Zero emission generation technologies should receive 1 credit for each MWh of retail electricity sold. Fossil generation with a carbon intensity equal to or greater than new supercritical coal should receive zero credits. Partial credits should be awarded to fossil-fuel utilities generating with a lower carbon-intensity than supercritical coal

proportional to their improvement over supercritical coal per MWh.

- Clean energy credits may be banked indefinitely.
- Generation from existing nuclear and hydroelectric utilities should be counted towards the overall target, but they should not be awarded credits. That is, the sum of all credited generation and generation from existing nuclear and hydroelectric plants should equal, by 2035, 80 percent of sales. The target for credited generation would therefore be reduced by the generation from existing nuclear and hydroelectric plants.

In addition, please also conduct the seven additional "sensitivity runs" identified below to consider the effects of changing certain important policy variables in the core policy:

Alternate crediting mechanisms

1) Award credits to all existing clean generation.
2) Deduct generation from existing hydroelectric and nuclear generation plants from the base against which a utility's requirement is calculated.
3) Credit technologies as follows:
    - New and uprated nuclear generation, new and incremental hydroelectric generation, and renewable generation should receive 1 credit per MWh of retail electricity sold.
    - New and existing Natural Gas Combined Cycle (NGCC) generators should receive 0.5 credits per MWh of retail electricity sold.
    - Coal equipped with carbon capture and storage at greater than 90% capture efficiency should receive 0.9 credits per MWh of retail electricity sold.
    - Natural Gas equipped with carbon capture and storage at greater than 95% capture efficiency should receive 0.95 credits per MWh of retail electricity sold.
    - Existing nuclear and hydroelectric generators should receive 0.1 credits per MWh of retail electricity sold.

Exclusion of small utilities

4) Exempt all utilities selling less than 4 million MWh per year from compliance with the standard.

Alternative compliance payment:

5) Allow compliance alternately to be achieved through a payment that begins at 2.1 cents per kilowatt hour and rises at an inflation-adjusted rate of 5% per year.
6) Allow compliance alternately to be achieved through a payment that begins at 3.0 cents per kilowatt hour and rises at an inflation-adjusted rate of 5% per year.

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

September 30, 2011

Dr. Howard Gruenspecht
Acting Administrator and Deputy Administrator
Energy Information Administration
1000 Independence Ave. SW
Washington, DC 20585

Dear Dr. Gruenspecht:

Upon further consideration of the design parameters for a Clean Energy Standard (CES), I would like to modify my original request for modeling dated August 16, 2011 as follows:

Please use the following set of overall targets for clean energy:

Year of compliance	Overall Clean Energy Target
2015	45%
2020	50%
2025	60%
2030	70%
2035	80%
2040	85%
2045	90%
2050	95%

The overall clean energy targets should be increased linearly between each interim target, and held constant after 2050.

The overall clean energy target for each of the modeling scenarios I have requested should equal the percentage of the total retail sales generated by clean energy as calculated using the methodology included in the original request. In each scenario the total clean energy required to be generated based on covered sales, plus any non-targeted clean energy (existing nuclear and hydro generation, if applicable), should be equal to the share of all electricity sales indicated in the table above. The sole exception is in model scenario #4, in which utilities with annual sales of less than 4,000,000 MWh are exempt from having a compliance obligation. For scenario #4, the overall clean energy targets should be applied only to the total retail sales from utilities with annual retail sales greater than 4,000,000 MWh.

Thank you for your attention to this request. I ask that my staff be briefed prior to the release of information. Should you or your staff have any questions, please contact Kevin Rennert with the Senate Committee on Energy and Natural Resources at (202) 224-7826.

Sincerely,

Jeff Bingaman
Chairman

Appendix B: Summary Tables

Table B1. The BCES and alternative cases compared to the Reference case, 2025

	2009	2025				2025				
	Ref	Ref	BCES	All Clean	Partial Credit	Revised Baseline	Small Utilities	Credit Cap 2.1	Credit Cap 3.0	Stnds + Cds
Generation (billion kilowatthours)										
Coal	1,772	2,049	1,431	1,305	1,387	1,180	1,767	1,714	1,571	1,358
Petroleum	41	45	43	44	44	44	45	45	45	43
Natural Gas	931	1,002	1,341	1,342	1,269	1,486	1,164	1,193	1,243	1,314
Nuclear	799	871	859	906	942	889	878	857	843	826
Conventional Hydropower	274	306	322	319	300	321	316	298	312	322
Geothermal	15	25	28	25	31	24	27	22	23	24
Municipal Waste	18	17	17	17	17	17	17	17	17	17
Wood and Other Biomass	38	162	303	289	295	301	241	266	314	296
Solar	3	18	18	33	18	35	18	18	18	21
Wind	71	153	233	251	285	252	179	193	226	216
Other	18	16	16	16	16	16	16	16	16	16
Total Generation	3,981	4,665	4,612	4,547	4,603	4,566	4,669	4,640	4,627	4,452
Capacity (gigawatts)										
Coal	317	323	278	254	275	252	297	298	288	267
Petroleum	116	87	86	85	92	86	88	91	90	83
Natural Gas	351	382	407	400	383	407	395	384	385	391
Nuclear	101	110	109	115	119	112	111	108	106	105
Conventional Hydropower	78	79	83	82	78	82	81	79	80	83
Geothermal	2	3	4	3	4	3	4	3	3	3
Municipal Waste	4	4	4	4	4	4	4	4	4	4
Wood and Other Biomass	7	17	17	17	17	17	17	17	17	17
Solar	2	11	11	17	11	18	11	11	11	12
Wind	32	53	77	86	97	86	61	67	78	75
Other (including pumped storage)	24	25	25	25	25	25	25	25	25	25
Total	1,033	1,095	1,101	1,089	1,106	1,093	1,094	1,087	1,087	1,065

Table B1. The BCES and alternative cases compared to the Reference case, 2025 (cont)

	2009	2025	2025							
	Ref	Ref	BCES	All Clean	Partial Credit	Revised Baseline	Small Utilities	Credit Cap 2.1	Credit Cap 3.0	Stnds + Cds
Prices (2009 cents/kWh)										
Credit Price	0.0	0.0	6.1	6.4	5.9	8.3	2.9	3.4	4.9	6.0
Electricity Price	9.8	9.0	9.4	10.0	9.5	9.8	8.9	9.2	9.3	9.3
Residential	11.5	10.7	11.2	11.7	11.3	11.5	10.7	11.0	11.1	11.2
Commercial	10.1	9.3	9.5	10.2	9.7	10.0	9.1	9.4	9.5	9.4
Industrial	6.8	6.3	6.5	7.0	6.6	6.9	6.2	6.4	6.5	6.4
Average Delivered Natural Gas Price (2009 dollars/Mcf)	7.5	8.1	8.5	8.5	8.4	8.7	8.2	8.3	8.4	8.3
Expenditures (billion 2009 dollars)										
Total Electricity Expenditures	350	373	383	399	387	396	370	379	382	365
Residential Electricity Expenditures	156	157	161	167	162	165	156	159	160	152
Household Electricity Expenditures (2009 Dollars/Household)	1,379	1,162	1,198	1,237	1,205	1,227	1,158	1,181	1,189	1,124
Natural Gas Expenditures	156	187	211	212	209	227	197	201	206	206
Electricity Sector Natural Gas Expenditures	34	39	59	57	57	70	48	51	54	57
Non-Electricity Sector Natural Gas Expenditures	122	148	153	155	152	158	149	151	152	149
CES Compliance			34	60	37	46	25	34	34	0
Credits Required (percent of sales)			31	59	35	34	25	25	28	0
Credits Achieved (percent of sales)			33	60	36	34	25	25	34	0
Generation Achieved (percent of sales)			44	72	71	49	35	36	40	0
Total Electricity Sales (billion kilowatthours)[1]	3,556	4,105	4,073	3,981	4,065	4,022	4,128	4,089	4,080	3,924
Emissions										
Sulfur Dioxide (short tons)	5.7	4.1	3.4	3.3	3.2	3.3	3.8	3.3	3.2	3.0
Nitrogen Oxide (short tons)	2.0	2.0	1.8	1.7	1.7	1.5	1.9	2.0	1.9	1.7
Mercury (short tons)	40.7	29.1	19.4	17.6	18.3	15.9	24.4	23.4	21.1	18.1
Carbon Dioxide (million metric tons CO_2)	2,160	2,345	1,840	1,704	1,762	1,623	2,118	2,082	1,955	1,762
Macroeconomic										
GDP (billion 2005 dollars)	12,881	20,012	19,963	19,947	19,951	19,947	19,994	19,990	19,983	19,942
Per Capita GDP (thousand 2005 dollars/person)	42	56	56	56	56	56	56	56	56	56
Employment, Non-Farm (million)	131	156	156	156	156	156	156	156	156	156
Employment, Manufacturing (million)	12	16	16	16	16	16	16	16	16	16

1 Exlcudes sales in Alaska and Hawaii

Source: U.S. Energy Information Administration, National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d2100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Table B2. The BCES and alternative cases compared to the Reference case, 2035

	2009	2035	2035							
	Ref	Ref	BCES	All Clean	Partial Credit	Revised Baseline	Small Utilities	Credit Cap 2.1	Credit Cap 3.0	Stnds+ Cds
Generation (billion kilowatthours)										
Coal	1,772	2,184	1,044	747	936	737	1,629	1,619	1,212	983
Petroleum	41	47	43	43	43	44	45	44	43	42
Natural Gas	931	1,293	1,980	1,840	1,658	2,007	1,277	1,432	1,582	1,778
Nuclear	799	868	783	1,114	1,269	999	1,105	932	1,048	748
Conventional Hydropower	274	314	312	319	300	323	322	322	329	321
Geothermal	15	42	49	51	55	50	53	50	51	52
Municipal Waste	18	17	17	17	17	17	17	17	17	17
Wood and Other Biomass	38	181	295	243	271	245	323	350	301	285
Solar	3	21	24	65	22	66	23	25	47	53
Wind	71	159	351	355	363	327	319	241	360	325
Other	18	16	16	16	16	16	16	16	16	16
Total Generation	3,981	5,142	4,916	4,811	4,950	4,831	5,131	5,049	5,007	4,620
Capacity (gigawatts)				1						
Coal	317	330	260	249	269	249	304	305	290	243
Petroleum	116	87	83	83	86	83	84	86	82	81
Natural Gas	351	455	496	458	448	483	443	455	470	450
Nuclear	101	110	155	142	163	127	141	118	138	138
Conventional Hydropower	78	81	83	82	78	83	83	83	84	83
Geothermal	2	6	6	7	7	7	7	7	7	7
Municipal Waste	4	4	4	4	4	4	4	4	4	4
Wood and Other Biomass	7	20	20	20	20	20	20	20	20	20
Solar	2	13	14	33	13	33	13	14	24	26
Wind	32	55	116	120	123	109	105	81	119	108
Other (including pumped storage)	24	25	25	25	25	25	25	25	25	25
Total	1,033	1,185	1,263	1,222	1,236	1,221	1,228	1,198	1,262	1,185

Table B2. The BCES and alternative cases compared to the Reference case, 2035 (cont)

	2009	2035	2035							
	Ref	Ref	BCES	All Clean	Partial Credit	Revised Baseline	Small Utilities	Credit Cap 2.1	Credit Cap 3.0	Stnds + Cds
Prices (2009 cents/kWh)										
Credit Price	0.0	0.0	11.6	11.4	9.9	13.7	4.7	5.6	8.0	10.6
Electricity Price	9.8	9.4	11.3	11.9	11.1	12.0	9.5	10.2	10.6	11.0
Residential	11.5	10.9	13.0	13.5	12.8	13.5	11.2	11.9	12.3	13.0
Commercial	10.1	9.4	11.4	12.0	11.2	12.1	9.5	10.3	10.6	11.0
Industrial	6.8	6.6	8.2	8.7	8.0	8.8	6.6	7.3	7.6	8.0
Average Delivered Natural Gas Price (2009 dollars/Mcf)	7.5	9.2	9.7	9.3	9.3	9.5	8.9	9.1	9.2	9.3
Expenditures (billion 2009 dollars)										
Total Electricity Expenditures	350	417	480	490	471	498	423	445	456	436
Residential Electricity Expenditures	156	176	201	205	197	207	179	187	192	176
Household Electricity Expenditures (2009 Dollars/Household)	1,379	1,196	1,366	1,398	1,342	1,409	1,217	1,276	1,307	1,198
Natural Gas Expenditures	156	227	279	261	256	277	217	230	241	253
Electricity Sector Natural Gas Expenditures	34	55	97	80	79	94	52	59	67	84
Non-Electricity Sector Natural Gas Expenditures	122	171	182	180	176	183	165	171	174	169
CES Compliance										
Credits Required (percent of sales)			56	80	58	74	42	56	56	56
Credits Achieved (percent of sales)			55	77	58	52	35	32	44	55
Generation Achieved (percent of sales)			72	92	93	70	45	43	56	70
Total Electricity Sales (billion kilowatthours)[1]	3,556	4,428	4,220	4,085	4,225	4,136	4,435	4,328	4,282	3,938
Emissions										
Sulfur Dioxide (short tons)	5.7	3.7	2.7	1.7	2.5	1.6	3.5	3.6	3.3	2.8
Nitrogen Oxide (short tons)	2.0	2.0	1.4	1.0	1.1	0.9	1.8	1.9	1.5	1.3
Mercury (short tons)	40.7	29.2	14.5	11.1	13.5	11.4	21.4	22.2	16.1	13.7
Carbon Dioxide (million metric tons CO_2)	2,160	2,500	1,428	1,008	986	962	1,921	1,950	1,491	1,235
Macroeconomic										
GDP (billion 2005 dollars)	12,881	25,686	25,562	25,528	25,563	25,610	25,641	25,650	25,606	25,472
Per Capita GDP (thousand 2005 dollars/person)	42	66	66	65	66	66	66	66	66	65
Employment, Non-Farm (million)	131	171	171	171	171	171	171	171	171	171
Employment, Manufacturing (million)	12	13	13	13	13	13	13	13	13	13

1 Exlcudes sales in Alaska and Hawaii

Source: U.S. Energy Information Administration, National Energy Modeling System, runs refhall.d082611b, cesbingbk.d100611a, cesbingbkac.d100611a, cesbingbkrb.d2100311a, cesbingbkpc.d100611a, cesbingbksm.d100311b, cesbingbkc21.d100311b, cesbingbkc30.d100311a, cesbingbksc.d100611a.

Appendix C: Map of NEMS Electricity Market Module Regions

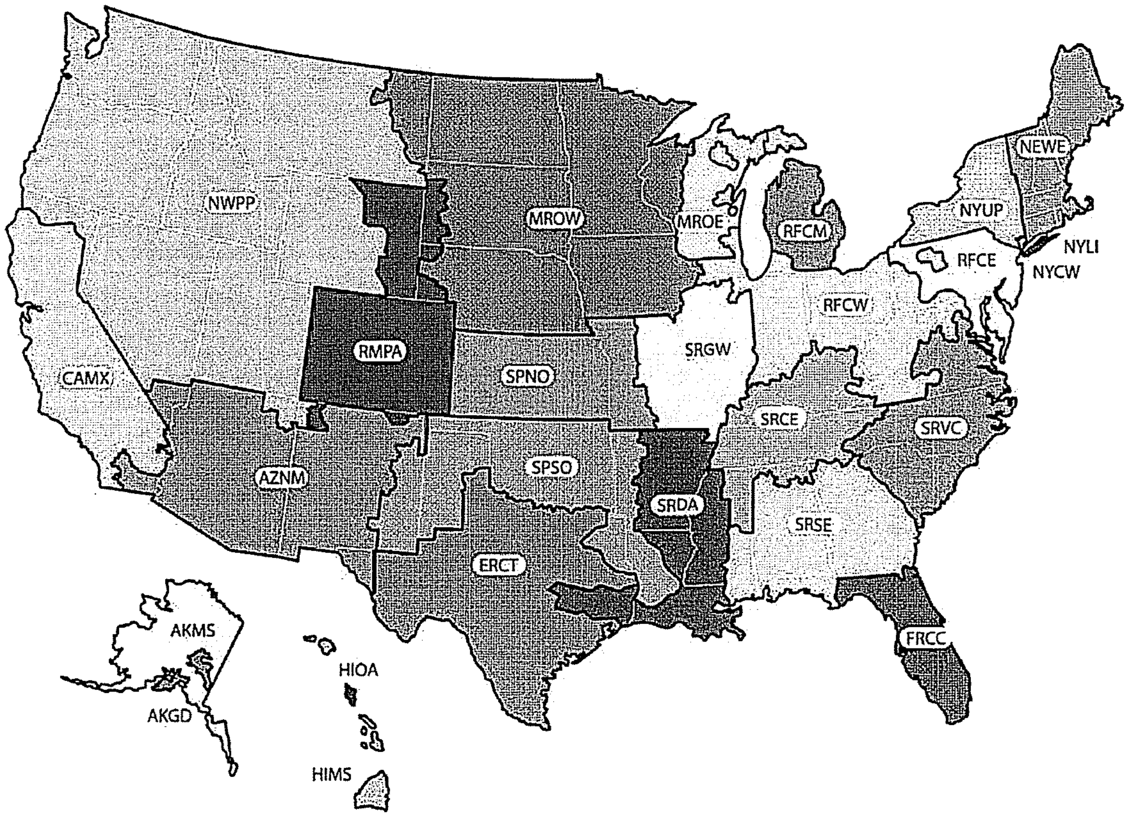

EXHIBIT ______

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2															
3		Report	Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman												
4		Scenario	cesbingbk			Clean energy standard									
5		Datekey	d100611a												
6		Release Date		November 2011											
7															
8															
9															
10															
11		**Click on link below to go to table. Press Ctrl+Home to return here.**													
12		1. Total Energy Supply, Disposition, and Price Summary													
13		2. Energy Consumption by Sector and Source													
14		3. Energy Prices by Sector and Source													
15		4. Residential Sector Key Indicators and Consumption													
16		5. Commercial Sector Key Indicators and Consumption													
17		6. Industrial Sector Key Indicators and Consumption													
18		7. Transportation Sector Key Indicators and Delivered Energy Consumption													
19		8. Electricity Supply, Disposition, Prices, and Emissions													
20		9. Electricity Generating Capacity													
21		10. Electricity Trade													
22		11. Liquid Fuels Supply and Disposition													
23		12. Petroleum Product Prices													
24		13. Natural Gas Supply, Disposition, and Prices													
25		14. Oil and Gas Supply													
26		15. Coal Supply, Disposition, and Prices													
27		16. Renewable Energy Generating Capacity and Generation													
28		17. Renewable Energy Consumption by Sector and Source													
29		18. Carbon Dioxide Emissions by Sector and Source													
30		19. Energy-Related Carbon Dioxide Emissions by End Use													
31		20. Macroeconomic Indicators													
32		21. National Impacts of Renewable or Clean Energy Standards (RPS/CES)													
33															
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SC EXHIBIT 27

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
41															
42															
43															
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45															
46															
47															
48															
49															
50	**1. Total Energy Supply, Disposition, and Price Summary**														
51	**(quadrillion Btu, unless otherwise noted)**														
52															
53	*Supply, Disposition, and Prices*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
54															
55	**Production**														
56	Crude Oil and Lease Condensate	10.51	11.34	11.87	11.76	11.58	12.02	12.39	12.52	12.83	13.08	13.13	13.17	13.09	13.06
57	Natural Gas Plant Liquids	2.41	2.57	2.64	2.63	2.70	2.73	2.76	2.95	2.91	2.94	3.01	3.08	3.18	3.29
58	Dry Natural Gas	20.83	21.50	21.71	21.48	21.27	21.75	22.09	23.90	23.58	23.84	24.33	24.82	25.26	25.51
59	Coal 1/	23.85	21.58	22.78	21.97	21.93	21.70	21.28	18.04	18.60	17.98	18.33	17.99	18.35	17.99
60	Nuclear Power	8.43	8.35	8.39	8.40	8.50	8.64	8.70	8.77	8.46	8.40	8.50	8.61	8.61	8.55
61	Hydropower	2.53	2.69	2.40	2.58	2.66	2.74	2.87	2.96	3.05	3.05	3.05	3.05	2.78	3.05
62	Biomass 2/	3.94	3.54	3.83	4.23	4.36	4.60	4.61	5.10	5.49	6.26	6.60	6.92	7.29	7.50
63	Other Renewable Energy 3/	1.12	1.29	1.54	1.72	2.44	2.60	2.61	2.61	2.61	2.64	2.64	2.64	2.69	2.69
64	Other 4/	0.19	0.34	0.56	0.93	0.65	0.69	0.77	0.70	0.71	0.78	0.79	0.79	0.80	0.74
65	**Total**	**73.80**	**73.20**	**75.70**	**75.69**	**76.10**	**77.47**	**78.07**	**77.56**	**78.23**	**78.97**	**80.37**	**81.07**	**82.04**	**82.37**
66															
67	**Imports**														
68	Crude Oil	21.39	19.70	20.19	20.16	19.84	19.78	19.44	19.19	18.83	18.54	18.43	18.32	18.29	18.38
69	Liquid Fuels 5/	6.32	5.40	4.53	4.72	5.22	5.36	5.35	5.31	5.35	5.32	5.32	5.29	5.25	5.20
70	Natural Gas	4.08	3.82	3.88	3.90	3.85	3.93	3.98	4.29	4.19	4.12	4.06	4.01	3.88	3.72
71	Other Imports 6/	0.96	0.61	0.55	0.68	0.82	0.86	0.86	0.83	0.81	0.80	0.36	0.51	0.50	0.66
72	**Total**	**32.76**	**29.53**	**29.15**	**29.46**	**29.74**	**29.94**	**29.62**	**29.61**	**29.18**	**28.78**	**28.18**	**28.13**	**27.93**	**27.96**
73															
74	**Exports**														
75	Petroleum 7/	3.78	4.17	4.25	4.24	3.27	3.26	3.24	3.25	3.28	3.37	3.44	3.49	3.52	3.55
76	Natural Gas	1.01	1.09	1.06	1.08	1.20	1.22	1.26	1.24	1.32	1.41	1.51	1.62	1.77	1.89
77	Coal	2.07	1.51	1.93	1.87	1.86	1.87	1.79	1.76	1.77	1.55	1.81	1.86	1.92	1.85
78	**Total**	**6.86**	**6.77**	**7.24**	**7.18**	**6.33**	**6.35**	**6.30**	**6.25**	**6.37**	**6.33**	**6.76**	**6.97**	**7.21**	**7.28**
79															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
41															
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50															
51															
52															**2009-**
53	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
54															
55															
56	13.08	12.89	12.67	12.54	12.45	12.55	12.58	12.65	12.71	12.90	13.19	13.44	13.35	13.27	0.6%
57	3.44	3.61	3.78	3.81	3.84	3.89	3.93	3.93	3.97	4.05	4.08	4.13	4.15	4.17	1.9%
58	25.86	26.09	26.14	26.24	26.45	26.68	27.03	27.17	27.56	28.17	28.72	29.43	30.03	31.30	1.5%
59	18.09	17.85	17.80	17.56	17.39	16.98	16.46	16.09	15.52	14.87	14.36	14.47	15.07	15.03	-1.4%
60	8.46	8.59	8.76	8.98	9.22	9.49	9.80	10.16	10.57	10.86	11.25	10.69	9.25	8.18	-0.1%
61	3.05	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.15	3.15	3.07	0.5%
62	7.75	8.07	8.48	8.79	9.02	9.23	9.54	9.56	9.61	9.61	9.50	9.78	10.04	10.09	4.1%
63	2.69	2.86	3.05	3.27	3.52	3.77	4.09	4.44	4.77	4.91	4.95	4.97	5.01	5.10	5.4%
64	0.74	0.73	0.71	0.71	0.71	0.71	0.72	0.74	0.77	0.78	0.78	0.77	0.78	0.77	3.2%
65	**83.16**	**83.83**	**84.55**	**85.07**	**85.75**	**86.45**	**87.30**	**87.90**	**88.65**	**89.30**	**89.98**	**90.84**	**90.82**	**90.98**	**0.8%**
66															
67															
68	18.13	18.09	18.12	18.19	18.17	18.04	17.81	17.79	17.77	17.64	17.42	17.08	17.26	17.46	-0.5%
69	5.24	5.17	5.10	5.10	5.08	5.07	5.03	5.05	5.06	5.04	5.08	5.13	5.17	5.20	-0.1%
70	3.58	3.47	3.42	3.37	3.32	3.27	3.19	3.14	3.13	3.12	3.08	3.03	2.97	2.84	-1.1%
71	0.59	0.67	0.63	0.61	0.59	0.52	0.50	0.46	0.40	0.34	0.38	0.36	0.34	0.38	-1.8%
72	**27.53**	**27.40**	**27.27**	**27.26**	**27.15**	**26.90**	**26.53**	**26.45**	**26.36**	**26.15**	**25.96**	**25.60**	**25.75**	**25.88**	**-0.5%**
73															
74															
75	3.55	3.56	3.58	3.61	3.62	3.64	3.66	3.69	3.73	3.77	3.79	3.80	3.85	3.88	-0.3%
76	1.95	1.98	1.98	1.99	2.02	2.07	2.09	2.13	2.13	2.19	2.24	2.33	2.41	2.52	3.3%
77	1.86	1.84	1.85	1.84	1.82	1.80	1.67	1.66	1.64	1.64	1.61	1.70	1.42	1.33	-0.5%
78	**7.35**	**7.38**	**7.41**	**7.43**	**7.47**	**7.51**	**7.43**	**7.48**	**7.51**	**7.60**	**7.64**	**7.83**	**7.68**	**7.73**	**0.5%**
79															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
80	**Discrepancy 8/**	**-0.44**	**1.15**	**-0.20**	**-0.40**	**-0.32**	**-0.25**	**-0.25**	**-0.26**	**-0.27**	**-0.27**	**-0.25**	**-0.26**	**-0.25**	**-0.25**
81															
82	**Consumption**														
83	Liquid Fuels 9/	38.46	36.62	36.96	37.41	38.25	38.84	38.97	39.07	39.05	39.05	39.06	39.08	39.13	39.21
84	Natural Gas	23.85	23.32	24.32	24.34	23.90	24.44	24.79	26.93	26.43	26.53	26.86	27.19	27.35	27.33
85	Coal 10/	22.38	19.69	21.23	20.63	20.73	20.53	20.18	16.84	17.37	16.97	16.62	16.39	16.69	16.53
86	Nuclear Power	8.43	8.35	8.39	8.40	8.50	8.64	8.70	8.77	8.46	8.40	8.50	8.61	8.61	8.55
87	Hydropower	2.53	2.69	2.40	2.58	2.66	2.74	2.87	2.96	3.05	3.05	3.05	3.05	2.78	3.05
88	Biomass 11/	3.07	2.54	2.66	2.99	3.02	3.21	3.21	3.68	4.03	4.73	5.00	5.22	5.46	5.63
89	Other Renewable Energy 3/	1.12	1.29	1.54	1.72	2.44	2.60	2.61	2.61	2.61	2.64	2.64	2.64	2.69	2.69
90	Other 12/	0.31	0.32	0.32	0.30	0.31	0.31	0.31	0.31	0.32	0.31	0.30	0.30	0.29	0.30
91	**Total**	**100.14**	**94.81**	**97.82**	**98.36**	**99.82**	**101.31**	**101.65**	**101.18**	**101.30**	**101.68**	**102.04**	**102.48**	**103.01**	**103.28**
92															
93	**Prices (2009 dollars per unit)**														
94	Low Sulfur Light Price ($ per barrel) 13/	100.51	61.66	78.03	83.21	85.74	88.09	91.43	94.48	97.48	100.35	103.06	105.65	108.03	110.28
95	Imported Crude Oil Price ($ per barrel) 13,	93.44	59.04	74.86	80.32	80.68	82.96	85.08	86.73	88.74	91.35	93.91	96.22	98.51	100.58
96	Gas Price at Henry Hub ($ / mmBtu)	8.94	3.95	4.43	4.48	4.34	4.35	4.34	5.47	5.57	5.58	5.60	5.64	5.84	6.00
97	Gas Wellhead Price ($ / mmBtu) 14/	7.96	3.62	3.95	3.95	3.85	3.85	3.84	4.84	4.93	4.94	4.96	5.00	5.17	5.31
98	Gas Wellhead Price ($ / Mcf) 14/	8.18	3.71	4.05	4.06	3.95	3.95	3.94	4.97	5.06	5.07	5.09	5.13	5.31	5.45
99	Coal Minemouth Price ($ / ton) 15/	31.54	33.26	36.78	35.57	34.05	33.62	33.10	33.17	32.25	31.11	32.43	32.38	32.68	32.91
100	Coal Delivered Price ($ / million Btu) 16/	2.18	2.31	2.41	2.39	2.34	2.31	2.28	2.26	2.19	2.21	2.21	2.20	2.20	2.21
101	Electricity (cents per kilowatthour)	9.8	9.8	9.6	9.0	8.9	8.8	8.7	8.9	8.9	8.8	8.9	8.9	8.9	9.0
102															
103															
104	**Prices (nominal dollars per unit)**														
105	Low Sulfur Light Price ($ per barrel) 13/	99.57	61.66	78.71	85.05	88.69	92.70	97.93	103.32	108.78	114.36	119.93	125.36	130.73	135.89
106	Imported Crude Oil Price ($ per barrel) 13,	92.57	59.04	75.52	82.10	83.45	87.30	91.14	94.84	99.02	104.10	109.28	114.18	119.21	123.94
107	Gas Price at Henry Hub ($ / mmBtu)	8.86	3.95	4.47	4.58	4.49	4.57	4.65	5.98	6.22	6.35	6.52	6.70	7.07	7.39
108	Gas Wellhead Price ($ / mmBtu) 14/	7.89	3.62	3.99	4.04	3.98	4.05	4.12	5.30	5.50	5.63	5.77	5.93	6.26	6.54
109	Gas Wellhead Price ($ / Mcf) 14/	8.10	3.71	4.09	4.15	4.08	4.16	4.22	5.43	5.65	5.77	5.92	6.08	6.42	6.71
110	Coal Minemouth Price ($ / ton) 15/	31.25	33.26	37.11	36.36	35.22	35.38	35.45	36.27	35.99	35.45	37.74	38.42	39.55	40.56
111	Coal Delivered Price ($ / million Btu) 16/	2.16	2.31	2.43	2.44	2.42	2.43	2.45	2.47	2.44	2.52	2.57	2.61	2.66	2.72
112	Electricity (cents per kilowatthour)	9.7	9.8	9.6	9.2	9.2	9.2	9.4	9.7	9.9	10.1	10.3	10.6	10.8	11.1
113															
114															
115															
116															
117	1/ Includes waste coal.														
118	2/ Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric														
119	energy demand from wood. Refer to Table 17 for details.														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
80	**-0.25**	**-0.19**	**-0.13**	**-0.14**	**-0.03**	**-0.10**	**-0.06**	**-0.06**	**-0.06**	**-0.09**	**-0.02**	**0.00**	**-0.01**	**0.05**	**- -**
81															
82															
83	39.30	39.35	39.44	39.55	39.60	39.74	39.78	39.94	40.19	40.43	40.61	40.80	41.04	41.25	0.5%
84	27.47	27.57	27.56	27.61	27.72	27.87	28.12	28.18	28.56	29.11	29.56	30.13	30.59	31.62	1.2%
85	16.54	16.30	16.13	15.88	15.57	15.13	14.63	14.19	13.52	12.76	12.19	12.11	12.88	12.80	-1.6%
86	8.46	8.59	8.76	8.98	9.22	9.49	9.80	10.16	10.57	10.86	11.25	10.69	9.25	8.18	-0.1%
87	3.05	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.15	3.15	3.07	0.5%
88	5.78	5.94	6.15	6.32	6.42	6.52	6.61	6.60	6.55	6.48	6.34	6.48	6.67	6.72	3.8%
89	2.69	2.86	3.05	3.27	3.52	3.77	4.09	4.44	4.77	4.91	4.95	4.97	5.01	5.10	5.4%
90	0.30	0.29	0.28	0.27	0.26	0.26	0.26	0.26	0.23	0.25	0.26	0.26	0.30	0.34	0.3%
91	**103.59**	**104.04**	**104.54**	**105.04**	**105.46**	**105.94**	**106.46**	**106.93**	**107.56**	**107.95**	**108.33**	**108.61**	**108.89**	**109.08**	**0.5%**
92															
93															
94	112.45	114.55	116.36	117.98	119.07	120.31	120.92	121.94	122.70	123.29	123.72	123.59	123.97	124.14	2.7%
95	102.54	104.50	106.20	107.76	108.71	109.84	110.08	111.04	111.65	112.03	112.24	112.08	112.49	112.67	2.5%
96	6.14	6.28	6.44	6.57	6.68	6.75	6.83	6.82	6.86	6.98	7.13	7.43	7.70	7.92	2.7%
97	5.43	5.56	5.70	5.81	5.91	5.97	6.04	6.04	6.07	6.18	6.31	6.58	6.81	7.01	2.6%
98	5.57	5.71	5.85	5.96	6.07	6.13	6.20	6.20	6.23	6.34	6.48	6.75	6.99	7.19	2.6%
99	32.97	33.18	33.18	33.27	33.24	33.06	32.95	33.00	32.93	32.59	31.92	31.39	30.53	30.13	-0.4%
100	2.21	2.21	2.21	2.22	2.22	2.20	2.20	2.18	2.15	2.13	2.10	2.09	2.11	2.12	-0.3%
101	9.0	9.2	9.3	9.4	9.5	9.6	9.8	9.9	10.0	10.1	10.3	10.6	11.0	11.3	0.6%
102															
103															
104															
105	140.93	146.15	151.13	155.84	160.02	164.61	168.52	173.18	177.51	181.71	185.96	189.49	193.95	198.17	4.6%
106	128.51	133.33	137.94	142.34	146.09	150.28	153.41	157.69	161.52	165.11	168.69	171.84	175.99	179.87	4.4%
107	7.69	8.02	8.36	8.67	8.97	9.23	9.51	9.69	9.92	10.29	10.72	11.39	12.04	12.64	4.6%
108	6.81	7.10	7.40	7.68	7.95	8.17	8.42	8.58	8.78	9.11	9.49	10.08	10.66	11.19	4.4%
109	6.99	7.28	7.60	7.88	8.15	8.39	8.64	8.80	9.01	9.35	9.74	10.34	10.93	11.48	4.4%
110	41.32	42.33	43.09	43.95	44.68	45.23	45.92	46.87	47.63	48.03	47.98	48.12	47.76	48.10	1.4%
111	2.77	2.83	2.87	2.93	2.98	3.01	3.06	3.09	3.11	3.14	3.16	3.20	3.30	3.39	1.5%
112	11.3	11.7	12.0	12.4	12.8	13.2	13.6	14.1	14.5	14.9	15.5	16.3	17.1	18.1	2.4%
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

120 3/ Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and
121 non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources
122 and nonmarketed renewable energy. See Table 17 for selected nonmarketed residential and commercial renewable energy.
123 4/ Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
124 5/ Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
125 6/ Includes coal, coal coke (net), and electricity (net).
126 7/ Includes crude oil and petroleum products.
127 8/ Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
128 9/ Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum
129 coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table 17 for detailed
130 renewable liquid fuels consumption.
131 10/ Excludes coal converted to coal-based synthetic liquids.
132 11/ Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the
133 production of liquid fuels, but excludes the energy content of the liquid fuels.
134 12/ Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
135 13/ Weighted average price delivered to U.S. refiners.
136 14/ Represents lower 48 onshore and offshore supplies.
137 15/ Includes reported prices for both open market and captive mines.
138 16/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
139 Btu = British thermal unit.
140 Mcf = Thousand cubic feet.
141 - - = Not applicable.
142 Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009
143 are model results and may differ slightly from official EIA data reports.
144 Sources: 2008 natural gas supply values: U.S. Energy Information Administration (EIA), Natural Gas Annual
145 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010).
146 2009 natural gas supply values and natural gas wellhead price: EIA, Natural Gas Monthly,
147 DOE/EIA-0130(2010/07) (Washington, DC, July 2010).
148 2008 natural gas wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010).
149 2008 and 2009 coal minemouth and delivered coal prices: EIA,
150 Annual Coal Report 2009, DOE/EIA-0584(2009) (Washington, DC, October 2010).
151 2009 petroleum supply values and 2008 crude oil and lease condensate production: EIA,
152 Petroleum Supply Annual 2009, DOE/EIA-0340(2009)/1 (Washington, DC, July 2010).
153 Other 2008 petroleum supply values: EIA, Petroleum Supply Annual 2008, DOE/EIA-0340(2008)/1 (Washington, DC, June 2009).
154 2008 and 2009 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition
155 Report." Other 2008 and 2009 coal values: EIA, Quarterly Coal Report, October-December 2009, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010).
156 Other 2008 and 2009 values: EIA, Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).
157 Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
165															
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170															
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173															
174															
175	**2. Energy Consumption by Sector and Source**														
176	**(quadrillion Btu, unless otherwise noted)**														
177															
178	*Sector and Source*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
179															
180	**Residential**														
181	Liquefied Petroleum Gases	0.52	0.53	0.52	0.51	0.50	0.50	0.49	0.49	0.49	0.48	0.48	0.48	0.48	0.48
182	Kerosene	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
183	Distillate Fuel Oil	0.66	0.61	0.60	0.62	0.59	0.58	0.57	0.56	0.55	0.53	0.52	0.51	0.50	0.48
184	Liquid Fuels Subtotal	1.20	1.16	1.15	1.16	1.12	1.10	1.08	1.07	1.05	1.04	1.02	1.01	1.00	0.98
185	Natural Gas	5.00	4.87	4.90	4.89	4.91	4.94	4.96	4.92	4.91	4.88	4.89	4.90	4.91	4.90
186	Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
187	Renewable Energy 1/	0.44	0.43	0.42	0.42	0.41	0.40	0.40	0.40	0.41	0.41	0.41	0.42	0.42	0.42
188	Electricity	4.71	4.65	4.97	4.63	4.67	4.62	4.61	4.60	4.63	4.64	4.67	4.71	4.74	4.77
189	**Delivered Energy**	**11.36**	**11.12**	**11.44**	**11.10**	**11.12**	**11.07**	**11.06**	**11.01**	**11.00**	**10.98**	**11.00**	**11.04**	**11.08**	**11.08**
190	Electricity Related Losses	10.17	9.95	10.62	9.85	9.87	9.66	9.60	9.27	9.34	9.36	9.38	9.41	9.45	9.45
191	**Total**	**21.53**	**21.07**	**22.06**	**20.95**	**20.99**	**20.72**	**20.66**	**20.28**	**20.34**	**20.33**	**20.38**	**20.45**	**20.53**	**20.52**
192															
193	**Commercial**														
194	Liquefied Petroleum Gases	0.15	0.15	0.15	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
195	Motor Gasoline 2/	0.05	0.05	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
196	Kerosene	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
197	Distillate Fuel Oil	0.37	0.34	0.32	0.30	0.29	0.29	0.29	0.28	0.28	0.28	0.27	0.27	0.27	0.26
198	Residual Fuel Oil	0.07	0.06	0.04	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
199	Liquid Fuels Subtotal	0.64	0.60	0.56	0.55	0.56	0.55	0.55	0.55	0.54	0.54	0.54	0.54	0.54	0.53
200	Natural Gas	3.22	3.20	3.18	3.31	3.34	3.39	3.45	3.44	3.42	3.43	3.45	3.48	3.49	3.50
201	Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
202	Renewable Energy 3/	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
203	Electricity	4.56	4.51	4.60	4.63	4.67	4.72	4.78	4.85	4.91	4.98	5.06	5.13	5.20	5.26

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
165															
166															
167															
168															
169															
170															
171															
172															
173															
174															
175															
176															
177															**2009-**
178	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
179															
180															
181	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	-0.4%
182	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-1.5%
183	0.47	0.46	0.45	0.44	0.43	0.43	0.42	0.41	0.40	0.40	0.39	0.38	0.38	0.37	-1.9%
184	0.97	0.96	0.95	0.94	0.93	0.92	0.91	0.90	0.90	0.89	0.89	0.88	0.87	0.87	-1.1%
185	4.90	4.91	4.92	4.91	4.92	4.92	4.93	4.92	4.92	4.91	4.91	4.88	4.86	4.85	0.0%
186	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.1%
187	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.42	0.42	0.42	0.42	0.42	0.42	0.42	-0.1%
188	4.81	4.85	4.90	4.93	4.97	5.01	5.05	5.08	5.12	5.16	5.20	5.21	5.23	5.25	0.5%
189	**11.11**	**11.14**	**11.20**	**11.21**	**11.24**	**11.27**	**11.33**	**11.33**	**11.36**	**11.38**	**11.43**	**11.40**	**11.39**	**11.40**	**0.1%**
190	9.45	9.47	9.52	9.55	9.61	9.66	9.74	9.80	9.86	9.84	9.87	9.81	9.79	9.73	-0.1%
191	**20.56**	**20.62**	**20.72**	**20.76**	**20.85**	**20.93**	**21.07**	**21.13**	**21.22**	**21.23**	**21.29**	**21.21**	**21.18**	**21.12**	**0.0%**
192															
193															
194	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.2%
195	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.2%
196	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
197	0.26	0.26	0.26	0.26	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	-1.2%
198	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.3%
199	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	-0.5%
200	3.51	3.53	3.54	3.56	3.59	3.61	3.64	3.67	3.71	3.74	3.78	3.81	3.83	3.87	0.7%
201	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
202	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
203	5.33	5.39	5.46	5.53	5.60	5.67	5.74	5.80	5.87	5.94	6.01	6.06	6.11	6.14	1.2%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
204	**Delivered Energy**	**8.60**	**8.49**	**8.51**	**8.66**	**8.74**	**8.83**	**8.95**	**9.00**	**9.05**	**9.13**	**9.22**	**9.32**	**9.39**	**9.47**
205	Electricity Related Losses	9.85	9.66	9.85	9.84	9.87	9.87	9.96	9.76	9.91	10.04	10.14	10.24	10.35	10.41
206	**Total**	**18.44**	**18.15**	**18.35**	**18.49**	**18.61**	**18.70**	**18.91**	**18.76**	**18.97**	**19.17**	**19.36**	**19.56**	**19.74**	**19.88**
207															
208	**Industrial 4/**														
209	Liquefied Petroleum Gases	2.08	2.01	2.13	2.20	2.26	2.32	2.36	2.34	2.32	2.30	2.30	2.29	2.30	2.30
210	Motor Gasoline 2/	0.25	0.25	0.25	0.27	0.29	0.31	0.32	0.33	0.33	0.33	0.33	0.33	0.33	0.33
211	Distillate Fuel Oil	1.27	1.16	1.19	1.19	1.22	1.24	1.20	1.15	1.16	1.16	1.16	1.16	1.16	1.16
212	Residual Fuel Oil	0.20	0.17	0.18	0.18	0.17	0.17	0.17	0.18	0.17	0.17	0.17	0.17	0.17	0.17
213	Petrochemical Feedstocks	1.12	0.90	0.97	1.06	1.10	1.18	1.24	1.27	1.26	1.26	1.26	1.26	1.27	1.27
214	Other Petroleum 5/	3.98	3.45	3.39	3.44	3.87	3.95	3.96	4.05	4.01	3.97	3.94	3.92	3.89	3.89
215	Liquid Fuels Subtotal	8.91	7.94	8.11	8.34	8.92	9.16	9.24	9.33	9.25	9.20	9.17	9.14	9.12	9.12
216	Natural Gas	6.83	6.32	6.73	7.13	7.38	7.83	8.03	7.98	7.95	7.98	7.99	8.02	8.04	8.02
217	Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
218	Lease and Plant Fuel 6/	1.26	1.19	1.31	1.29	1.25	1.23	1.21	1.28	1.25	1.25	1.26	1.27	1.28	1.28
219	Natural Gas Subtotal	8.09	7.51	8.04	8.42	8.63	9.06	9.23	9.26	9.20	9.23	9.25	9.29	9.32	9.30
220	Metallurgical Coal	0.58	0.40	0.54	0.56	0.56	0.59	0.58	0.57	0.56	0.56	0.56	0.56	0.56	0.56
221	Other Industrial Coal	1.16	0.94	0.96	0.96	0.97	0.99	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
222	Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.11	0.11	0.11	0.12	0.13
223	Net Coal Coke Imports	0.04	-0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
224	Coal Subtotal	1.78	1.32	1.52	1.54	1.54	1.59	1.57	1.65	1.64	1.64	1.64	1.64	1.65	1.66
225	Biofuels Heat and Coproducts	0.98	0.67	0.74	0.94	0.81	0.83	0.84	0.85	0.86	0.91	0.97	1.06	1.18	1.27
226	Renewable Energy 7/	1.52	1.42	1.49	1.62	1.74	1.88	1.81	1.87	1.87	1.91	1.93	1.94	1.97	1.99
227	Electricity	3.44	3.01	3.20	3.32	3.41	3.56	3.55	3.54	3.52	3.52	3.53	3.53	3.54	3.54
228	**Delivered Energy**	**24.72**	**21.87**	**23.10**	**24.18**	**25.05**	**26.09**	**26.25**	**26.49**	**26.33**	**26.42**	**26.49**	**26.62**	**26.79**	**26.88**
229	Electricity Related Losses	7.44	6.44	6.84	7.07	7.20	7.45	7.39	7.14	7.10	7.11	7.08	7.06	7.06	7.00
230	**Total**	**32.16**	**28.32**	**29.94**	**31.25**	**32.25**	**33.54**	**33.64**	**33.63**	**33.43**	**33.53**	**33.57**	**33.67**	**33.84**	**33.88**
231															
232															
233	**Transportation**														
234	Liquefied Petroleum Gases	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02
235	E85 8/	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.10	0.18	0.24	0.31	0.21
236	Motor Gasoline 2/	16.87	16.82	16.88	16.88	16.96	17.03	17.03	17.01	16.98	16.85	16.71	16.60	16.48	16.58
237	Jet Fuel 9/	3.21	3.20	3.14	3.14	3.14	3.15	3.17	3.20	3.23	3.26	3.29	3.31	3.34	3.37
238	Distillate Fuel Oil 10/	6.04	5.54	5.69	5.93	6.15	6.44	6.49	6.51	6.57	6.66	6.76	6.84	6.93	7.00
239	Residual Fuel Oil	0.92	0.78	0.80	0.80	0.79	0.79	0.79	0.80	0.80	0.80	0.80	0.80	0.80	0.80
240	Other Petroleum 11/	0.17	0.16	0.16	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16
241	Liquid Fuels Subtotal	27.24	26.52	26.70	26.92	27.21	27.58	27.67	27.69	27.76	27.83	27.90	27.96	28.04	28.13
242	Pipeline Fuel Natural Gas	0.67	0.65	0.67	0.65	0.64	0.64	0.65	0.70	0.68	0.67	0.68	0.68	0.69	0.68

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
204	**9.54**	**9.62**	**9.71**	**9.80**	**9.89**	**9.98**	**10.08**	**10.18**	**10.28**	**10.39**	**10.49**	**10.57**	**10.64**	**10.72**	**0.9%**
205	10.46	10.54	10.61	10.72	10.84	10.95	11.06	11.20	11.31	11.34	11.41	11.42	11.43	11.39	0.6%
206	**20.01**	**20.16**	**20.32**	**20.52**	**20.73**	**20.93**	**21.14**	**21.38**	**21.59**	**21.73**	**21.89**	**21.99**	**22.07**	**22.10**	**0.8%**
207															
208															
209	2.30	2.30	2.30	2.29	2.27	2.25	2.23	2.21	2.20	2.19	2.17	2.15	2.13	2.10	0.2%
210	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.32	1.0%
211	1.16	1.16	1.15	1.15	1.15	1.15	1.14	1.13	1.13	1.13	1.12	1.12	1.12	1.12	-0.1%
212	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	-0.3%
213	1.28	1.28	1.28	1.28	1.27	1.26	1.26	1.25	1.25	1.24	1.24	1.23	1.22	1.21	1.2%
214	3.88	3.86	3.85	3.84	3.82	3.82	3.79	3.79	3.80	3.83	3.82	3.83	3.86	3.87	0.4%
215	9.12	9.10	9.08	9.06	9.01	8.97	8.91	8.88	8.87	8.87	8.83	8.81	8.80	8.78	0.4%
216	7.96	7.96	7.95	7.96	7.97	7.98	8.04	8.08	8.15	8.19	8.22	8.25	8.24	8.24	1.0%
217	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
218	1.29	1.29	1.29	1.28	1.29	1.29	1.30	1.30	1.31	1.33	1.35	1.37	1.40	1.46	0.8%
219	9.25	9.25	9.24	9.24	9.25	9.27	9.34	9.37	9.46	9.52	9.57	9.63	9.64	9.69	1.0%
220	0.56	0.55	0.54	0.53	0.52	0.51	0.51	0.50	0.49	0.48	0.47	0.47	0.46	0.45	0.4%
221	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.94	0.94	0.93	0.93	-0.1%
222	0.16	0.26	0.31	0.37	0.42	0.49	0.56	0.63	0.71	0.79	0.87	0.96	1.05	1.13	- -
223	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-5.3%
224	1.69	1.78	1.82	1.86	1.91	1.96	2.02	2.08	2.15	2.22	2.29	2.36	2.43	2.50	2.5%
225	1.37	1.54	1.73	1.88	1.99	2.09	2.23	2.26	2.30	2.34	2.36	2.46	2.50	2.51	5.2%
226	2.01	2.02	2.02	2.04	2.04	2.04	2.03	2.04	2.04	2.03	2.02	2.02	2.02	2.01	1.3%
227	3.53	3.51	3.49	3.47	3.43	3.38	3.33	3.28	3.24	3.19	3.14	3.09	3.05	3.01	0.0%
228	**26.97**	**27.20**	**27.38**	**27.54**	**27.63**	**27.71**	**27.86**	**27.91**	**28.05**	**28.17**	**28.21**	**28.37**	**28.44**	**28.50**	**1.0%**
229	6.93	6.86	6.78	6.72	6.63	6.53	6.42	6.33	6.23	6.09	5.95	5.82	5.71	5.57	-0.6%
230	**33.90**	**34.05**	**34.16**	**34.26**	**34.26**	**34.24**	**34.28**	**34.24**	**34.28**	**34.25**	**34.16**	**34.20**	**34.15**	**34.07**	**0.7%**
231															
232															
233															
234	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.4%
235	0.41	0.59	0.81	0.93	1.07	0.97	1.28	1.16	1.10	1.13	1.15	1.13	1.13	1.13	25.9%
236	16.36	16.17	15.96	15.89	15.75	15.95	15.68	15.90	16.11	16.22	16.34	16.48	16.60	16.74	0.0%
237	3.40	3.42	3.45	3.47	3.49	3.51	3.53	3.54	3.56	3.57	3.59	3.60	3.61	3.62	0.5%
238	7.08	7.15	7.23	7.31	7.39	7.46	7.53	7.60	7.69	7.78	7.86	7.94	8.05	8.14	1.5%
239	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.82	0.82	0.82	0.82	0.82	0.82	0.2%
240	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.1%
241	28.23	28.32	28.43	28.59	28.69	28.89	29.00	29.20	29.47	29.71	29.93	30.15	30.40	30.63	0.6%
242	0.69	0.69	0.69	0.68	0.68	0.69	0.69	0.69	0.69	0.70	0.71	0.72	0.73	0.78	0.7%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
243	Compressed Natural Gas	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
244	Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
245	Electricity	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
246	**Delivered Energy**	**27.95**	**27.23**	**27.42**	**27.62**	**27.91**	**28.29**	**28.38**	**28.45**	**28.51**	**28.59**	**28.66**	**28.74**	**28.83**	**28.93**
247	Electricity Related Losses	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07
248	**Total**	**28.00**	**27.28**	**27.47**	**27.67**	**27.96**	**28.34**	**28.44**	**28.51**	**28.57**	**28.65**	**28.72**	**28.80**	**28.90**	**29.00**
249															
250	**Delivered Energy Consumption, All Sectors**														
251	Liquefied Petroleum Gases	2.77	2.71	2.82	2.88	2.93	2.99	3.01	2.99	2.97	2.95	2.94	2.94	2.94	2.94
252	E85 8/	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.10	0.18	0.24	0.31	0.21
253	Motor Gasoline 2/	17.17	17.11	17.17	17.19	17.29	17.38	17.39	17.38	17.36	17.23	17.08	16.97	16.86	16.96
254	Jet Fuel 9/	3.21	3.20	3.14	3.14	3.14	3.15	3.17	3.20	3.23	3.26	3.29	3.31	3.34	3.37
255	Kerosene	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
256	Distillate Fuel Oil	8.34	7.65	7.80	8.04	8.25	8.54	8.54	8.50	8.56	8.63	8.70	8.77	8.86	8.91
257	Residual Fuel Oil	1.19	1.02	1.02	1.03	1.03	1.03	1.02	1.04	1.03	1.03	1.04	1.04	1.04	1.04
258	Petrochemical Feedstocks	1.12	0.90	0.97	1.06	1.10	1.18	1.24	1.27	1.26	1.26	1.26	1.26	1.27	1.27
259	Other Petroleum 12/	4.15	3.60	3.54	3.59	4.02	4.10	4.11	4.20	4.16	4.12	4.10	4.07	4.04	4.04
260	Liquid Fuels Subtotal	37.99	36.23	36.51	36.97	37.81	38.40	38.54	38.63	38.61	38.61	38.62	38.64	38.69	38.77
261	Natural Gas	15.07	14.42	14.84	15.35	15.66	16.19	16.47	16.39	16.33	16.34	16.39	16.45	16.50	16.48
262	Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
263	Lease and Plant Fuel 6/	1.26	1.19	1.31	1.29	1.25	1.23	1.21	1.28	1.25	1.25	1.26	1.27	1.28	1.28
264	Pipeline Natural Gas	0.67	0.65	0.67	0.65	0.64	0.64	0.65	0.70	0.68	0.67	0.68	0.68	0.69	0.68
265	Natural Gas Subtotal	17.00	16.26	16.82	17.30	17.55	18.06	18.33	18.36	18.26	18.27	18.33	18.41	18.47	18.45
266	Metallurgical Coal	0.58	0.40	0.54	0.56	0.56	0.59	0.58	0.57	0.56	0.56	0.56	0.56	0.56	0.56
267	Other Coal	1.24	1.01	1.02	1.03	1.04	1.06	1.05	1.04	1.04	1.04	1.04	1.04	1.04	1.04
268	Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.11	0.11	0.11	0.12	0.13
269	Net Coal Coke Imports	0.04	-0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
270	Coal Subtotal	1.86	1.39	1.59	1.60	1.61	1.66	1.64	1.71	1.71	1.71	1.71	1.71	1.72	1.73
271	Biofuels Heat and Coproducts	0.98	0.67	0.74	0.94	0.81	0.83	0.84	0.85	0.86	0.91	0.97	1.06	1.18	1.27
272	Renewable Energy 13/	2.07	1.96	2.02	2.15	2.26	2.39	2.32	2.38	2.39	2.43	2.46	2.47	2.49	2.52
273	Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
274	Electricity	12.73	12.20	12.79	12.61	12.78	12.93	12.97	13.02	13.08	13.18	13.29	13.41	13.52	13.61
275	**Delivered Energy**	**72.63**	**68.70**	**70.46**	**71.56**	**72.82**	**74.27**	**74.65**	**74.95**	**74.90**	**75.11**	**75.37**	**75.70**	**76.08**	**76.35**
276	Electricity Related Losses	27.51	26.11	27.36	26.80	27.00	27.04	27.00	26.23	26.40	26.57	26.67	26.78	26.93	26.94
277	**Total**	**100.14**	**94.81**	**97.82**	**98.36**	**99.82**	**101.31**	**101.65**	**101.18**	**101.30**	**101.68**	**102.04**	**102.48**	**103.01**	**103.28**
278															
279															
280	**Electric Power 14/**														
281	Distillate Fuel Oil	0.11	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.09

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
243	0.08	0.08	0.09	0.10	0.10	0.11	0.12	0.12	0.13	0.14	0.14	0.15	0.15	0.16	7.2%
244	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
245	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	4.5%
246	**29.04**	**29.13**	**29.25**	**29.41**	**29.53**	**29.74**	**29.86**	**30.07**	**30.35**	**30.62**	**30.85**	**31.09**	**31.35**	**31.65**	**0.6%**
247	0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.11	0.12	0.12	0.13	0.13	0.14	4.0%
248	**29.11**	**29.21**	**29.34**	**29.50**	**29.63**	**29.84**	**29.97**	**30.18**	**30.47**	**30.73**	**30.97**	**31.22**	**31.49**	**31.78**	**0.6%**
249															
250															
251	2.95	2.95	2.94	2.93	2.91	2.89	2.88	2.86	2.85	2.84	2.82	2.81	2.78	2.76	0.1%
252	0.41	0.59	0.81	0.93	1.07	0.97	1.28	1.16	1.10	1.13	1.15	1.13	1.13	1.13	25.9%
253	16.74	16.55	16.34	16.27	16.13	16.33	16.05	16.28	16.49	16.59	16.71	16.85	16.97	17.11	0.0%
254	3.40	3.42	3.45	3.47	3.49	3.51	3.53	3.54	3.56	3.57	3.59	3.60	3.61	3.62	0.5%
255	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.4%
256	8.98	9.03	9.09	9.17	9.23	9.29	9.34	9.39	9.47	9.55	9.62	9.69	9.79	9.87	1.0%
257	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.05	1.05	1.05	0.1%
258	1.28	1.28	1.28	1.28	1.27	1.26	1.26	1.25	1.25	1.24	1.24	1.23	1.22	1.21	1.2%
259	4.04	4.01	4.01	4.00	3.98	3.97	3.95	3.95	3.96	3.98	3.98	3.99	4.01	4.03	0.4%
260	38.86	38.91	39.00	39.11	39.16	39.30	39.35	39.51	39.76	40.00	40.18	40.37	40.60	40.81	0.5%
261	16.45	16.47	16.51	16.53	16.57	16.61	16.72	16.79	16.91	16.98	17.05	17.08	17.09	17.12	0.7%
262	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
263	1.29	1.29	1.29	1.28	1.29	1.29	1.30	1.30	1.31	1.33	1.35	1.37	1.40	1.46	0.8%
264	0.69	0.69	0.69	0.68	0.68	0.69	0.69	0.69	0.69	0.70	0.71	0.72	0.73	0.78	0.7%
265	18.43	18.45	18.48	18.50	18.54	18.59	18.71	18.78	18.91	19.02	19.11	19.18	19.22	19.35	0.7%
266	0.56	0.55	0.54	0.53	0.52	0.51	0.51	0.50	0.49	0.48	0.47	0.47	0.46	0.45	0.4%
267	1.04	1.03	1.03	1.03	1.03	1.03	1.02	1.02	1.02	1.01	1.01	1.00	1.00	0.99	-0.1%
268	0.16	0.26	0.31	0.37	0.42	0.49	0.56	0.63	0.71	0.79	0.87	0.96	1.05	1.13	- -
269	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-5.3%
270	1.76	1.84	1.88	1.93	1.97	2.03	2.09	2.15	2.22	2.29	2.35	2.43	2.50	2.57	2.4%
271	1.37	1.54	1.73	1.88	1.99	2.09	2.23	2.26	2.30	2.34	2.36	2.46	2.50	2.51	5.2%
272	2.54	2.55	2.56	2.57	2.57	2.58	2.57	2.57	2.57	2.57	2.56	2.56	2.55	2.55	1.0%
273	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
274	13.71	13.80	13.89	13.97	14.04	14.11	14.18	14.22	14.28	14.35	14.41	14.44	14.46	14.48	0.7%
275	**76.66**	**77.10**	**77.55**	**77.96**	**78.29**	**78.71**	**79.13**	**79.49**	**80.05**	**80.56**	**80.98**	**81.43**	**81.83**	**82.26**	**0.7%**
276	26.92	26.95	27.00	27.08	27.17	27.23	27.33	27.44	27.51	27.39	27.35	27.18	27.06	26.82	0.1%
277	**103.59**	**104.04**	**104.54**	**105.04**	**105.46**	**105.94**	**106.46**	**106.93**	**107.56**	**107.95**	**108.33**	**108.61**	**108.89**	**109.08**	**0.5%**
278															
279															
280															
281	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.08	0.08	-0.6%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
282	Residual Fuel Oil	0.37	0.30	0.34	0.34	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35	0.35	0.35
283	Liquid Fuels Subtotal	0.47	0.40	0.45	0.44	0.44	0.44	0.43	0.44	0.44	0.44	0.44	0.44	0.44	0.44
284	Natural Gas	6.85	7.06	7.50	7.04	6.36	6.38	6.46	8.57	8.18	8.26	8.54	8.78	8.88	8.88
285	Steam Coal	20.51	18.30	19.64	19.02	19.12	18.87	18.54	15.13	15.66	15.26	14.91	14.68	14.98	14.79
286	Nuclear Power	8.43	8.35	8.39	8.40	8.50	8.64	8.70	8.77	8.46	8.40	8.50	8.61	8.61	8.55
287	Renewable Energy 15/	3.67	3.89	3.85	4.20	5.05	5.32	5.52	6.02	6.44	7.08	7.27	7.37	7.25	7.58
288	Electricity Imports	0.11	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.12	0.11	0.10	0.10	0.09	0.10
289	**Total 16/**	**40.24**	**38.31**	**40.15**	**39.41**	**39.77**	**39.97**	**39.97**	**39.25**	**39.49**	**39.75**	**39.96**	**40.18**	**40.44**	**40.55**
290															
291	**Total Energy Consumption**														
292	Liquefied Petroleum Gases	2.77	2.71	2.82	2.88	2.93	2.99	3.01	2.99	2.97	2.95	2.94	2.94	2.94	2.94
293	E85 8/	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.10	0.18	0.24	0.31	0.21
294	Motor Gasoline 2/	17.17	17.11	17.17	17.19	17.29	17.38	17.39	17.38	17.36	17.23	17.08	16.97	16.86	16.96
295	Jet Fuel 9/	3.21	3.20	3.14	3.14	3.14	3.15	3.17	3.20	3.23	3.26	3.29	3.31	3.34	3.37
296	Kerosene	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
297	Distillate Fuel Oil	8.45	7.75	7.91	8.14	8.35	8.64	8.64	8.60	8.65	8.72	8.80	8.87	8.95	9.00
298	Residual Fuel Oil	1.56	1.32	1.37	1.38	1.38	1.37	1.36	1.38	1.38	1.38	1.38	1.38	1.38	1.39
299	Petrochemical Feedstocks	1.12	0.90	0.97	1.06	1.10	1.18	1.24	1.27	1.26	1.26	1.26	1.26	1.27	1.27
300	Other Petroleum 12/	4.15	3.60	3.54	3.59	4.02	4.10	4.11	4.20	4.16	4.12	4.10	4.07	4.04	4.04
301	Liquid Fuels Subtotal	38.46	36.62	36.96	37.41	38.25	38.84	38.97	39.07	39.05	39.05	39.06	39.08	39.13	39.21
302	Natural Gas	21.92	21.48	22.34	22.40	22.02	22.57	22.93	24.96	24.50	24.61	24.92	25.24	25.38	25.37
303	Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
304	Lease and Plant Fuel 6/	1.26	1.19	1.31	1.29	1.25	1.23	1.21	1.28	1.25	1.25	1.26	1.27	1.28	1.28
305	Pipeline Natural Gas	0.67	0.65	0.67	0.65	0.64	0.64	0.65	0.70	0.68	0.67	0.68	0.68	0.69	0.68
306	Natural Gas Subtotal	23.85	23.32	24.32	24.34	23.90	24.44	24.79	26.93	26.43	26.53	26.86	27.19	27.35	27.33
307	Metallurgical Coal	0.58	0.40	0.54	0.56	0.56	0.59	0.58	0.57	0.56	0.56	0.56	0.56	0.56	0.56
308	Other Coal	21.75	19.31	20.66	20.05	20.16	19.93	19.60	16.17	16.70	16.30	15.95	15.72	16.01	15.83
309	Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.11	0.11	0.11	0.12	0.13
310	Net Coal Coke Imports	0.04	-0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
311	Coal Subtotal	22.38	19.69	21.23	20.63	20.73	20.53	20.18	16.84	17.37	16.97	16.62	16.39	16.69	16.53
312	Nuclear Power	8.43	8.35	8.39	8.40	8.50	8.64	8.70	8.77	8.46	8.40	8.50	8.61	8.61	8.55
313	Biofuels Heat and Coproducts	0.98	0.67	0.74	0.94	0.81	0.83	0.84	0.85	0.86	0.91	0.97	1.06	1.18	1.27
314	Renewable Energy 17/	5.74	5.85	5.86	6.34	7.31	7.72	7.84	8.40	8.83	9.51	9.72	9.84	9.74	10.09
315	Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
316	Electricity Imports	0.11	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.12	0.11	0.10	0.10	0.09	0.10
317	**Total**	**100.14**	**94.81**	**97.82**	**98.36**	**99.82**	**101.31**	**101.65**	**101.18**	**101.30**	**101.68**	**102.04**	**102.48**	**103.01**	**103.28**
318															
319	**Energy Use & Related Statistics**														
320	Delivered Energy Use	72.63	68.70	70.46	71.56	72.82	74.27	74.65	74.95	74.90	75.11	75.37	75.70	76.08	76.35

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
282	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.7%
283	0.44	0.44	0.44	0.44	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.4%
284	9.05	9.11	9.08	9.11	9.18	9.28	9.41	9.40	9.65	10.09	10.45	10.95	11.37	12.27	2.1%
285	14.79	14.46	14.25	13.95	13.59	13.10	12.55	12.05	11.31	10.48	9.83	9.69	10.38	10.23	-2.2%
286	8.46	8.59	8.76	8.98	9.22	9.49	9.80	10.16	10.57	10.86	11.25	10.69	9.25	8.18	-0.1%
287	7.60	7.86	8.07	8.30	8.53	8.78	9.06	9.36	9.61	9.64	9.53	9.59	9.79	9.83	3.6%
288	0.10	0.09	0.08	0.07	0.06	0.06	0.06	0.06	0.03	0.04	0.06	0.06	0.10	0.14	0.7%
289	**40.63**	**40.74**	**40.89**	**41.05**	**41.21**	**41.35**	**41.51**	**41.66**	**41.79**	**41.74**	**41.76**	**41.61**	**41.52**	**41.29**	**0.3%**
290															
291															
292	2.95	2.95	2.94	2.93	2.91	2.89	2.88	2.86	2.85	2.84	2.82	2.81	2.78	2.76	0.1%
293	0.41	0.59	0.81	0.93	1.07	0.97	1.28	1.16	1.10	1.13	1.15	1.13	1.13	1.13	25.9%
294	16.74	16.55	16.34	16.27	16.13	16.33	16.05	16.28	16.49	16.59	16.71	16.85	16.97	17.11	0.0%
295	3.40	3.42	3.45	3.47	3.49	3.51	3.53	3.54	3.56	3.57	3.59	3.60	3.61	3.62	0.5%
296	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.4%
297	9.07	9.12	9.18	9.25	9.31	9.37	9.41	9.47	9.55	9.63	9.69	9.77	9.87	9.95	1.0%
298	1.39	1.39	1.39	1.39	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.41	0.3%
299	1.28	1.28	1.28	1.28	1.27	1.26	1.26	1.25	1.25	1.24	1.24	1.23	1.22	1.21	1.2%
300	4.04	4.01	4.01	4.00	3.98	3.97	3.95	3.95	3.96	3.98	3.98	3.99	4.01	4.03	0.4%
301	39.30	39.35	39.44	39.55	39.60	39.74	39.78	39.94	40.19	40.43	40.61	40.80	41.04	41.25	0.5%
302	25.50	25.59	25.59	25.64	25.75	25.90	26.13	26.19	26.56	27.08	27.50	28.04	28.47	29.39	1.2%
303	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
304	1.29	1.29	1.29	1.28	1.29	1.29	1.30	1.30	1.31	1.33	1.35	1.37	1.40	1.46	0.8%
305	0.69	0.69	0.69	0.68	0.68	0.69	0.69	0.69	0.69	0.70	0.71	0.72	0.73	0.78	0.7%
306	27.47	27.57	27.56	27.61	27.72	27.87	28.12	28.18	28.56	29.11	29.56	30.13	30.59	31.62	1.2%
307	0.56	0.55	0.54	0.53	0.52	0.51	0.51	0.50	0.49	0.48	0.47	0.47	0.46	0.45	0.4%
308	15.82	15.49	15.28	14.98	14.62	14.13	13.57	13.07	12.32	11.49	10.84	10.69	11.38	11.23	-2.1%
309	0.16	0.26	0.31	0.37	0.42	0.49	0.56	0.63	0.71	0.79	0.87	0.96	1.05	1.13	- -
310	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-5.3%
311	16.54	16.30	16.13	15.88	15.57	15.13	14.63	14.19	13.52	12.76	12.19	12.11	12.88	12.80	-1.6%
312	8.46	8.59	8.76	8.98	9.22	9.49	9.80	10.16	10.57	10.86	11.25	10.69	9.25	8.18	-0.1%
313	1.37	1.54	1.73	1.88	1.99	2.09	2.23	2.26	2.30	2.34	2.36	2.46	2.50	2.51	5.2%
314	10.14	10.42	10.63	10.87	11.10	11.35	11.63	11.93	12.18	12.20	12.09	12.14	12.34	12.38	2.9%
315	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
316	0.10	0.09	0.08	0.07	0.06	0.06	0.06	0.06	0.03	0.04	0.06	0.06	0.10	0.14	0.7%
317	**103.59**	**104.04**	**104.54**	**105.04**	**105.46**	**105.94**	**106.46**	**106.93**	**107.56**	**107.95**	**108.33**	**108.61**	**108.89**	**109.08**	**0.5%**
318															
319															
320	76.66	77.10	77.55	77.96	78.29	78.71	79.13	79.49	80.05	80.56	80.98	81.43	81.83	82.26	0.7%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
321	Total Energy Use	100.14	94.81	97.82	98.36	99.82	101.31	101.65	101.18	101.30	101.68	102.04	102.48	103.01	103.28
322	Ethanol Consumed in Motor Gasoline anc	0.77	0.95	1.10	1.26	1.27	1.29	1.31	1.33	1.36	1.44	1.52	1.60	1.69	1.63
323	Population (millions)	305.17	307.84	310.83	313.84	316.88	319.94	323.04	326.16	329.30	332.46	335.63	338.82	342.01	345.22
324	US GDP (billion 2005 dollars)	13229	12881	13221	13506	14038	14587	14923	15306	15688	16098	16517	16929	17367	17844
325	**Carbon Dioxide Emissions (million metric**														
326	tons carbon dioxide equivalent)	5838.0	5425.5	5653.5	5613.5	5640.8	5679.1	5666.8	5465.6	5479.1	5436.6	5416.3	5408.9	5442.6	5435.4

1/ Includes wood used for residential heating. See Table 4 and/or Table 17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and electricity generation from wind and solar photovoltaic sources.

2/ Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

3/ Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table 5 and/or Table 17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and electricity generation from wind and solar photovoltaic sources.

4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

5/ Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

6/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.

7/ Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.

8/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.

9/ Includes only kerosene type.

10/ Diesel fuel for on- and off- road use.

11/ Includes aviation gasoline and lubricants.

12/ Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

13/ Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

14/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

15/ Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.

16/ Includes non-biogenic municipal waste not included above.

17/ Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 consumption based on: U.S. Energy Information Administration (EIA),

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
321	103.59	104.04	104.54	105.04	105.46	105.94	106.46	106.93	107.56	107.95	108.33	108.61	108.89	109.08	0.5%
322	1.76	1.86	1.99	2.06	2.09	2.11	2.22	2.23	2.22	2.25	2.27	2.29	2.30	2.31	3.5%
323	348.42	351.63	354.85	358.06	361.27	364.47	367.68	370.88	374.08	377.28	380.48	383.68	386.88	390.09	0.9%
324	18375	18889	19408	19963	20497	21028	21548	22074	22645	23217	23776	24353	24954	25562	2.7%
325															
326	5439.6	5412.2	5394.8	5377.6	5357.0	5332.3	5288.6	5256.4	5221.0	5180.9	5137.0	5138.9	5204.3	5195.0	-0.2%
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
365	Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).														
366	2008 and 2009 population and gross domestic product: IHS Global Insight Industry and Employment models,														
367	September 2010. 2008 and 2009 carbon dioxide emissions: EIA,														
368	Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009) (Washington, DC, December 2010).														
369	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
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400	**3. Energy Prices by Sector and Source**														
401	**(2009 dollars per million Btu, unless otherwise noted)**														
402															
403	*Sector and Source*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
404															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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403	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2009-2035**
404															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
405	**Residential**														
406	Liquefied Petroleum Gases	29.46	24.63	26.49	26.72	28.53	29.02	29.47	29.61	30.00	30.54	31.07	31.56	32.00	32.40
407	Distillate Fuel Oil	24.75	18.12	20.68	21.67	19.94	20.33	20.70	21.06	21.86	22.62	23.32	23.72	24.18	24.46
408	Natural Gas	13.62	11.88	10.99	10.25	10.01	9.91	9.79	10.83	11.01	11.15	11.25	11.35	11.64	11.81
409	Electricity	33.16	33.62	33.51	31.44	31.45	31.50	31.42	31.89	31.80	31.67	31.68	31.63	31.63	31.79
410															
411	**Commercial**														
412	Liquefied Petroleum Gases	26.70	21.49	20.99	26.27	25.08	25.56	26.01	26.15	26.54	27.08	27.61	28.09	28.52	28.93
413	Distillate Fuel Oil	21.81	15.97	18.22	19.08	18.08	18.46	18.84	19.21	19.98	20.72	21.40	21.79	22.24	22.56
414	Residual Fuel	15.80	13.45	13.81	14.92	11.64	12.24	12.81	13.24	13.68	14.14	14.58	14.77	15.18	15.52
415	Natural Gas	11.99	9.68	8.88	9.02	8.64	8.37	8.09	9.09	9.24	9.32	9.39	9.46	9.71	9.85
416	Electricity	30.50	29.51	28.42	27.45	26.93	26.44	26.15	26.59	26.55	26.45	26.61	26.69	26.79	27.01
417															
418	**Industrial 1/**														
419	Liquefied Petroleum Gases	24.95	20.59	22.10	27.91	22.06	22.57	23.00	23.14	23.51	24.06	24.61	25.10	25.55	25.97
420	Distillate Fuel Oil	22.57	16.56	18.90	19.79	18.09	18.49	18.89	19.28	20.04	20.78	21.48	21.88	22.34	22.67
421	Residual Fuel Oil	16.26	12.05	12.32	13.35	13.59	13.91	14.38	14.76	15.20	15.58	16.01	16.28	16.66	16.91
422	Natural Gas 2/	9.08	5.25	4.77	4.82	4.71	4.69	4.68	5.72	5.86	5.89	5.92	5.95	6.13	6.28
423	Metallurgical Coal	4.53	5.43	6.19	6.10	6.07	6.14	6.02	5.99	5.83	6.10	6.16	6.28	6.35	6.40
424	Other Industrial Coal	2.93	3.05	3.06	3.01	2.98	2.98	2.94	2.86	2.76	2.87	2.84	2.83	2.81	2.82
425	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	1.76	1.73	1.76	1.77	1.78	1.79	1.81
426	Electricity	19.97	19.79	18.89	17.87	17.61	17.32	17.22	17.58	17.62	17.53	17.63	17.72	17.81	18.03
427															
428	**Transportation**														
429	Liquefied Petroleum Gases 3/	30.23	25.52	27.24	27.50	29.34	29.81	30.25	30.38	30.77	31.31	31.84	32.31	32.75	33.15
430	E85 4/	35.36	20.50	24.89	26.09	23.70	24.98	25.78	26.36	26.85	26.51	27.68	28.41	28.73	28.81
431	Motor Gasoline 5/	27.06	19.28	22.12	23.18	23.35	24.60	25.37	25.95	26.44	27.07	27.51	27.75	28.22	28.22
432	Jet Fuel 6/	23.30	12.59	15.76	16.88	18.09	18.46	18.70	18.96	19.72	20.44	21.11	21.50	21.95	22.29
433	Diesel Fuel (distillate fuel oil) 7/	27.97	17.79	21.07	22.10	21.29	21.67	22.06	22.44	23.19	23.94	24.66	25.16	25.68	25.75
434	Residual Fuel Oil	14.57	10.57	10.82	11.72	11.43	11.73	12.18	12.60	13.10	13.45	13.89	14.16	14.53	14.85
435	Natural Gas 8/	17.20	12.71	12.01	11.99	11.82	11.77	11.73	12.69	12.78	12.80	12.81	12.83	13.00	13.10
436	Electricity	34.68	34.93	30.19	30.62	30.11	29.40	28.86	28.91	28.38	27.71	27.68	27.87	27.99	28.36
437															
438	**Electric Power 9/**														
439	Distillate Fuel Oil	19.56	14.33	16.38	17.22	15.65	16.01	16.36	16.65	17.36	18.11	18.76	19.17	19.57	19.87
440	Residual Fuel Oil	14.75	8.96	11.43	12.12	11.93	12.26	12.71	12.84	13.32	13.68	14.12	14.37	14.74	15.04
441	Natural Gas	9.10	4.82	5.03	4.67	4.48	4.40	4.35	5.57	5.64	5.66	5.68	5.73	5.89	6.01
442	Steam Coal	2.07	2.20	2.27	2.24	2.20	2.16	2.13	2.08	2.02	2.03	2.02	2.01	2.01	2.02
443															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
405															
406	32.79	33.19	33.51	33.82	34.00	34.23	34.27	34.48	34.61	34.66	34.67	34.57	34.59	34.57	1.3%
407	24.90	25.34	25.75	26.06	26.34	26.52	26.85	27.04	26.80	26.88	26.95	27.43	27.57	27.67	1.6%
408	11.96	12.12	12.28	12.43	12.59	12.71	12.83	12.86	12.96	13.13	13.30	13.65	13.93	14.15	0.7%
409	31.83	32.14	32.48	32.76	33.15	33.48	33.89	34.25	34.54	34.81	35.32	36.22	37.19	38.21	0.5%
410															
411															
412	29.31	29.70	30.02	30.33	30.50	30.73	30.76	30.97	31.09	31.14	31.15	31.05	31.06	31.05	1.4%
413	23.02	23.47	23.88	24.17	24.47	24.63	25.00	25.16	24.85	24.93	25.00	25.39	25.53	25.62	1.8%
414	16.03	16.70	16.91	17.09	17.22	17.38	17.43	17.49	17.57	17.62	17.72	17.82	17.96	18.08	1.1%
415	9.98	10.11	10.25	10.37	10.50	10.59	10.69	10.69	10.75	10.88	11.02	11.31	11.55	11.75	0.7%
416	27.12	27.44	27.75	27.98	28.34	28.64	29.11	29.46	29.73	29.86	30.32	31.17	32.19	33.27	0.5%
417															
418															
419	26.39	26.78	27.13	27.44	27.60	27.82	27.83	28.03	28.15	28.20	28.21	28.11	28.11	28.10	1.2%
420	23.18	23.67	24.08	24.36	24.71	24.86	25.27	25.41	24.98	25.07	25.14	25.52	25.66	25.76	1.7%
421	17.29	17.70	18.01	18.25	18.38	18.52	18.60	18.59	18.66	18.53	18.57	18.87	18.96	19.00	1.8%
422	6.40	6.51	6.64	6.73	6.83	6.89	6.96	6.96	6.98	7.09	7.24	7.52	7.78	8.01	1.6%
423	6.37	6.44	6.43	6.52	6.52	6.55	6.56	6.58	6.58	6.62	6.63	6.62	6.61	6.57	0.7%
424	2.81	2.82	2.81	2.83	2.83	2.80	2.80	2.77	2.74	2.72	2.70	2.69	2.75	2.80	-0.3%
425	1.73	1.74	1.70	1.67	1.65	1.66	1.67	1.67	1.63	1.60	1.58	1.60	1.63	1.69	- -
426	18.24	18.53	18.73	18.96	19.30	19.60	20.04	20.45	20.78	21.05	21.58	22.33	23.16	24.08	0.8%
427															
428															
429	33.53	33.92	34.24	34.55	34.72	34.94	34.97	35.18	35.30	35.34	35.34	35.24	35.25	35.23	1.2%
430	28.36	29.02	29.46	29.70	30.28	30.35	30.85	30.82	30.24	30.33	30.45	30.83	31.02	31.14	1.6%
431	28.61	29.13	29.47	29.70	30.24	30.26	30.85	30.81	30.19	30.27	30.38	30.77	30.96	31.07	1.9%
432	22.59	22.95	23.33	23.67	23.84	24.13	24.28	24.49	24.49	24.64	24.69	25.08	25.23	25.35	2.7%
433	26.23	26.71	27.12	27.37	27.53	27.84	28.10	28.36	27.81	27.89	27.95	28.27	28.41	28.49	1.8%
434	15.20	15.53	15.81	16.07	16.24	16.43	16.58	16.61	16.71	16.54	16.55	16.59	16.70	16.69	1.8%
435	13.19	13.27	13.35	13.42	13.49	13.54	13.59	13.57	13.57	13.65	13.75	13.98	14.19	14.37	0.5%
436	28.77	29.50	30.17	30.84	31.57	32.28	33.18	33.84	34.40	34.92	35.85	37.31	38.86	40.31	0.6%
437															
438															
439	20.20	20.53	20.86	21.17	21.30	21.51	21.68	21.95	21.94	22.01	22.10	22.50	22.64	22.77	1.8%
440	15.40	15.78	16.07	16.31	16.47	16.63	16.75	16.78	16.88	16.77	16.80	16.87	16.98	16.99	2.5%
441	6.13	6.25	6.34	6.42	6.52	6.59	6.68	6.68	6.73	6.86	7.02	7.31	7.60	7.89	1.9%
442	2.02	2.03	2.03	2.04	2.04	2.02	2.02	2.00	1.97	1.94	1.91	1.90	1.94	1.96	-0.4%
443															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
444															
445	**Average Price to All Users 10/**														
446	Liquefied Petroleum Gases	20.70	17.43	18.04	20.66	20.64	21.02	21.39	21.53	21.90	22.40	22.89	23.33	23.74	24.11
447	E85 4/	35.36	20.50	24.89	26.09	23.70	24.98	25.78	26.36	26.85	26.51	27.68	28.41	28.73	28.81
448	Motor Gasoline 5/	26.88	19.23	22.07	23.16	23.35	24.60	25.37	25.95	26.44	27.07	27.51	27.75	28.22	28.22
449	Jet Fuel	23.30	12.59	15.76	16.88	18.09	18.46	18.70	18.96	19.72	20.44	21.11	21.50	21.95	22.29
450	Distillate Fuel Oil	26.53	17.51	20.54	21.55	20.42	20.95	21.36	21.76	22.52	23.28	24.00	24.49	25.00	25.13
451	Residual Fuel Oil	14.89	10.53	11.26	12.17	11.83	12.16	12.61	12.97	13.45	13.81	14.24	14.50	14.87	15.18
452	Natural Gas	10.56	7.28	6.82	6.59	6.43	6.32	6.22	7.15	7.30	7.35	7.38	7.42	7.62	7.77
453	Metallurgical Coal	4.53	5.43	6.19	6.10	6.07	6.14	6.02	5.99	5.83	6.10	6.16	6.28	6.35	6.40
454	Other Coal	2.12	2.25	2.31	2.28	2.24	2.20	2.18	2.14	2.07	2.09	2.08	2.07	2.07	2.07
455	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	1.76	1.73	1.76	1.77	1.78	1.79	1.81
456	Electricity	28.65	28.69	28.02	26.40	26.10	25.74	25.59	26.02	26.01	25.91	26.01	26.06	26.14	26.35
457															
458	**Non-Renewable Energy Expenditures by Sector**														
459	**(billion 2009 dollars)**														
460	Residential	256.17	238.63	246.88	223.25	222.87	221.16	220.34	226.89	228.25	228.78	230.68	232.32	235.14	237.41
461	Commercial	191.84	174.64	169.66	168.40	165.73	164.53	164.49	171.77	173.98	176.05	179.50	182.49	185.98	189.64
462	Industrial	249.51	179.30	193.42	213.52	200.84	210.83	216.02	227.62	229.73	232.98	236.30	239.18	243.80	247.40
463	Transportation	717.39	474.92	554.93	588.26	595.43	629.50	648.22	662.07	679.75	697.28	711.10	719.95	732.96	740.37
464	Total Non-Renewable Expenditures	1414.92	1067.49	1164.89	1193.43	1184.87	1226.01	1249.06	1288.35	1311.71	1335.09	1357.59	1373.93	1397.88	1414.82
465	Transportation Renewable Expenditures	0.04	0.06	0.07	0.08	0.13	0.17	0.20	0.23	0.26	2.64	4.92	6.75	8.98	5.91
466	**Total Expenditures**	**1414.96**	**1067.55**	**1164.96**	**1193.51**	**1185.00**	**1226.18**	**1249.26**	**1288.58**	**1311.97**	**1337.73**	**1362.51**	**1380.68**	**1406.86**	**1420.73**
467															
468															
469	**Prices in Nominal Dollars**														
470	**Residential**														
471	Liquefied Petroleum Gases	29.18	24.63	26.72	27.31	29.51	30.54	31.57	32.38	33.48	34.81	36.16	37.45	38.72	39.93
472	Distillate Fuel Oil	24.52	18.12	20.87	22.15	20.62	21.39	22.18	23.03	24.39	25.78	27.14	28.14	29.26	30.15
473	Natural Gas	13.49	11.88	11.09	10.48	10.36	10.43	10.49	11.84	12.29	12.71	13.10	13.47	14.09	14.55
474	Electricity	32.85	33.62	33.81	32.14	32.53	33.15	33.66	34.88	35.49	36.09	36.86	37.53	38.28	39.17
475															
476	**Commercial**														
477	Liquefied Petroleum Gases	26.45	21.49	21.18	26.85	25.94	26.90	27.86	28.60	29.61	30.86	32.12	33.33	34.52	35.64
478	Distillate Fuel Oil	21.61	15.97	18.38	19.50	18.70	19.43	20.18	21.01	22.30	23.61	24.90	25.85	26.92	27.80
479	Residual Fuel	15.66	13.45	13.94	15.25	12.04	12.88	13.72	14.48	15.27	16.11	16.96	17.53	18.37	19.12
480	Natural Gas	11.88	9.68	8.96	9.22	8.94	8.81	8.66	9.94	10.31	10.63	10.93	11.23	11.75	12.14
481	Electricity	30.22	29.51	28.67	28.06	27.85	27.83	28.01	29.07	29.62	30.15	30.96	31.67	32.42	33.29
482															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
444															
445															
446	24.47	24.83	25.15	25.44	25.62	25.85	25.90	26.10	26.24	26.30	26.33	26.25	26.29	26.30	1.6%
447	28.36	29.02	29.46	29.70	30.28	30.35	30.85	30.82	30.24	30.33	30.45	30.83	31.02	31.14	1.6%
448	28.61	29.13	29.47	29.70	30.24	30.26	30.85	30.81	30.19	30.27	30.38	30.77	30.96	31.07	1.9%
449	22.59	22.95	23.33	23.67	23.84	24.13	24.28	24.49	24.49	24.64	24.69	25.08	25.23	25.35	2.7%
450	25.62	26.11	26.52	26.79	27.14	27.27	27.70	27.82	27.33	27.40	27.47	27.82	27.95	28.04	1.8%
451	15.54	15.91	16.20	16.44	16.60	16.77	16.90	16.92	17.02	16.88	16.90	16.98	17.08	17.09	1.9%
452	7.89	8.01	8.14	8.25	8.36	8.43	8.52	8.52	8.55	8.66	8.79	9.05	9.30	9.50	1.0%
453	6.37	6.44	6.43	6.52	6.52	6.55	6.56	6.58	6.58	6.62	6.63	6.62	6.61	6.57	0.7%
454	2.08	2.09	2.08	2.10	2.10	2.08	2.08	2.06	2.04	2.02	1.99	1.98	2.02	2.04	-0.4%
455	1.73	1.74	1.70	1.67	1.65	1.66	1.67	1.67	1.63	1.60	1.58	1.60	1.63	1.69	- -
456	26.49	26.83	27.16	27.44	27.85	28.20	28.70	29.11	29.44	29.70	30.25	31.13	32.13	33.19	0.6%
457															
458															
459															
460	239.84	243.45	247.75	250.71	254.63	258.20	262.73	265.25	268.27	271.65	276.65	282.91	289.74	296.61	0.8%
461	192.76	197.13	201.52	205.52	210.26	214.68	220.09	224.47	228.52	232.31	238.04	246.37	255.26	264.33	1.6%
462	250.79	254.57	257.32	259.65	261.28	261.86	263.10	263.28	262.76	263.14	264.22	268.07	270.89	273.20	1.6%
463	748.40	758.93	765.53	773.40	784.05	795.19	802.39	813.12	808.95	817.44	826.00	844.07	856.40	866.62	2.3%
464	1431.80	1454.09	1472.12	1489.27	1510.22	1529.92	1548.31	1566.12	1568.49	1584.55	1604.92	1641.41	1672.28	1700.76	1.8%
465	11.63	17.17	23.95	27.52	32.50	29.57	39.42	35.65	33.42	34.41	35.01	34.76	35.08	35.29	28.0%
466	**1443.42**	**1471.26**	**1496.06**	**1516.79**	**1542.72**	**1559.50**	**1587.73**	**1601.77**	**1601.91**	**1618.96**	**1639.93**	**1676.17**	**1707.36**	**1736.04**	**1.9%**
467															
468															
469															
470															
471	41.10	42.34	43.53	44.68	45.70	46.84	47.76	48.96	50.06	51.08	52.10	53.00	54.11	55.19	3.2%
472	31.21	32.33	33.45	34.42	35.40	36.29	37.43	38.40	38.77	39.62	40.51	42.05	43.14	44.18	3.5%
473	14.99	15.46	15.95	16.43	16.92	17.39	17.88	18.27	18.74	19.35	19.99	20.92	21.79	22.58	2.5%
474	39.89	41.01	42.18	43.28	44.55	45.80	47.24	48.64	49.96	51.31	53.09	55.53	58.18	60.99	2.3%
475															
476															
477	36.73	37.89	39.00	40.06	40.99	42.04	42.88	43.98	44.98	45.90	46.82	47.61	48.60	49.56	3.3%
478	28.85	29.95	31.01	31.92	32.89	33.70	34.85	35.74	35.95	36.75	37.58	38.93	39.94	40.90	3.7%
479	20.08	21.31	21.97	22.58	23.15	23.78	24.29	24.84	25.41	25.97	26.64	27.32	28.10	28.86	3.0%
480	12.50	12.91	13.32	13.70	14.11	14.49	14.90	15.18	15.54	16.03	16.57	17.34	18.07	18.76	2.6%
481	33.99	35.01	36.05	36.96	38.08	39.19	40.57	41.84	43.00	44.00	45.57	47.79	50.36	53.11	2.3%
482															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
483	**Industrial 1/**														
484	Liquefied Petroleum Gases	24.72	20.59	22.29	28.53	22.82	23.75	24.64	25.31	26.23	27.42	28.63	29.79	30.92	32.00
485	Distillate Fuel Oil	22.36	16.56	19.06	20.23	18.71	19.46	20.24	21.08	22.36	23.68	24.99	25.96	27.04	27.93
486	Residual Fuel Oil	16.11	12.05	12.42	13.65	14.06	14.64	15.40	16.14	16.96	17.75	18.64	19.32	20.17	20.84
487	Natural Gas 2/	9.00	5.25	4.82	4.93	4.87	4.94	5.02	6.26	6.54	6.71	6.88	7.06	7.42	7.74
488	Metallurgical Coal	4.49	5.43	6.24	6.23	6.28	6.46	6.45	6.55	6.51	6.95	7.16	7.46	7.69	7.88
489	Other Industrial Coal	2.90	3.05	3.09	3.08	3.08	3.13	3.15	3.13	3.08	3.27	3.30	3.35	3.40	3.48
490	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	1.92	1.93	2.01	2.07	2.11	2.17	2.23
491	Electricity	19.79	19.79	19.06	18.27	18.22	18.23	18.45	19.23	19.66	19.98	20.51	21.02	21.56	22.22
492															
493															
494	**Transportation**														
495	Liquefied Petroleum Gases 3/	29.95	25.52	27.48	28.11	30.35	31.37	32.40	33.23	34.33	35.68	37.05	38.34	39.63	40.85
496	E85 4/	35.03	20.50	25.11	26.67	24.51	26.29	27.61	28.82	29.96	30.21	32.21	33.71	34.77	35.50
497	Motor Gasoline 5/	26.81	19.28	22.31	23.70	24.15	25.88	27.18	28.37	29.50	30.85	32.01	32.93	34.15	34.78
498	Jet Fuel 6/	23.09	12.59	15.90	17.26	18.71	19.42	20.03	20.73	22.00	23.29	24.57	25.52	26.56	27.47
499	Diesel Fuel (distillate fuel oil) 7/	27.71	17.79	21.26	22.58	22.02	22.80	23.63	24.54	25.88	27.28	28.69	29.86	31.07	31.73
500	Residual Fuel Oil	14.43	10.57	10.92	11.98	11.82	12.35	13.05	13.78	14.62	15.33	16.16	16.80	17.58	18.30
501	Natural Gas 8/	17.04	12.71	12.12	12.25	12.23	12.39	12.56	13.87	14.26	14.59	14.91	15.23	15.73	16.15
502	Electricity	34.36	34.93	30.45	31.30	31.15	30.94	30.91	31.61	31.67	31.58	32.21	33.07	33.87	34.95
503															
504	**Electric Power 9/**														
505	Distillate Fuel Oil	19.38	14.33	16.53	17.60	16.18	16.85	17.53	18.21	19.37	20.64	21.83	22.75	23.68	24.49
506	Residual Fuel Oil	14.61	8.96	11.53	12.39	12.34	12.90	13.62	14.04	14.86	15.59	16.43	17.05	17.84	18.53
507	Natural Gas	9.02	4.82	5.08	4.77	4.63	4.63	4.66	6.09	6.29	6.45	6.61	6.80	7.13	7.41
508	Steam Coal	2.05	2.20	2.29	2.29	2.27	2.27	2.28	2.28	2.26	2.31	2.35	2.38	2.43	2.49
509															
510	**Average Price to All Users 10/**														
511	Liquefied Petroleum Gases	20.51	17.43	18.20	21.12	21.34	22.12	22.92	23.54	24.44	25.52	26.64	27.69	28.73	29.71
512	E85 4/	35.03	20.50	25.11	26.67	24.51	26.29	27.61	28.82	29.96	30.21	32.21	33.71	34.77	35.50
513	Motor Gasoline 5/	26.63	19.23	22.27	23.67	24.15	25.88	27.18	28.37	29.50	30.85	32.01	32.93	34.15	34.78
514	Jet Fuel	23.09	12.59	15.90	17.26	18.71	19.42	20.03	20.73	22.00	23.29	24.57	25.52	26.56	27.47
515	Distillate Fuel Oil	26.28	17.51	20.72	22.03	21.12	22.05	22.88	23.79	25.13	26.53	27.92	29.05	30.25	30.97
516	Residual Fuel Oil	14.75	10.53	11.35	12.44	12.24	12.80	13.51	14.18	15.00	15.73	16.57	17.21	18.00	18.71
517	Natural Gas	10.46	7.28	6.88	6.73	6.65	6.65	6.66	7.82	8.15	8.37	8.59	8.81	9.23	9.57
518	Metallurgical Coal	4.49	5.43	6.24	6.23	6.28	6.46	6.45	6.55	6.51	6.95	7.16	7.46	7.69	7.88
519	Other Coal	2.10	2.25	2.33	2.33	2.32	2.32	2.33	2.34	2.31	2.38	2.42	2.45	2.50	2.56
520	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	1.92	1.93	2.01	2.07	2.11	2.17	2.23
521	Electricity	28.38	28.69	28.26	26.98	27.00	27.09	27.41	28.45	29.02	29.52	30.27	30.93	31.63	32.48

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
483															
484	33.07	34.17	35.24	36.24	37.10	38.07	38.79	39.80	40.72	41.56	42.41	43.09	43.98	44.85	3.0%
485	29.05	30.20	31.28	32.18	33.21	34.01	35.22	36.08	36.14	36.94	37.78	39.12	40.14	41.12	3.6%
486	21.67	22.58	23.39	24.11	24.70	25.34	25.92	26.40	26.99	27.32	27.91	28.94	29.66	30.33	3.6%
487	8.02	8.31	8.62	8.90	9.18	9.43	9.70	9.88	10.10	10.45	10.89	11.53	12.17	12.78	3.5%
488	7.99	8.22	8.35	8.61	8.77	8.96	9.14	9.34	9.51	9.75	9.97	10.15	10.33	10.49	2.6%
489	3.52	3.60	3.65	3.74	3.80	3.83	3.90	3.94	3.97	4.00	4.06	4.13	4.30	4.46	1.5%
490	2.16	2.22	2.20	2.21	2.22	2.27	2.32	2.38	2.36	2.35	2.38	2.45	2.55	2.70	- -
491	22.86	23.64	24.32	25.05	25.94	26.82	27.93	29.05	30.07	31.02	32.44	34.23	36.23	38.44	2.6%
492															
493															
494															
495	42.03	43.28	44.48	45.63	46.66	47.81	48.74	49.96	51.07	52.09	53.12	54.03	55.15	56.24	3.1%
496	35.54	37.02	38.26	39.24	40.70	41.53	42.99	43.76	43.75	44.70	45.76	47.27	48.53	49.70	3.5%
497	35.86	37.17	38.28	39.23	40.63	41.40	42.99	43.76	43.68	44.61	45.66	47.18	48.44	49.61	3.7%
498	28.31	29.28	30.30	31.26	32.04	33.01	33.84	34.78	35.43	36.32	37.11	38.45	39.47	40.47	4.6%
499	32.88	34.08	35.22	36.16	36.99	38.09	39.16	40.27	40.24	41.11	42.01	43.34	44.44	45.48	3.7%
500	19.04	19.82	20.54	21.22	21.83	22.48	23.10	23.59	24.18	24.37	24.88	25.43	26.12	26.64	3.6%
501	16.53	16.94	17.34	17.73	18.13	18.53	18.94	19.27	19.63	20.12	20.67	21.43	22.20	22.95	2.3%
502	36.05	37.64	39.19	40.74	42.42	44.17	46.24	48.05	49.76	51.47	53.88	57.20	60.79	64.35	2.4%
503															
504															
505	25.32	26.19	27.10	27.96	28.62	29.43	30.22	31.17	31.75	32.44	33.21	34.50	35.42	36.35	3.6%
506	19.30	20.14	20.88	21.55	22.13	22.75	23.35	23.83	24.42	24.72	25.24	25.87	26.56	27.11	4.3%
507	7.69	7.97	8.23	8.49	8.76	9.02	9.30	9.48	9.73	10.12	10.55	11.20	11.89	12.60	3.8%
508	2.53	2.59	2.63	2.69	2.74	2.77	2.81	2.84	2.85	2.86	2.87	2.92	3.04	3.12	1.4%
509															
510															
511	30.66	31.68	32.66	33.60	34.43	35.37	36.10	37.07	37.95	38.76	39.57	40.24	41.13	41.98	3.4%
512	35.54	37.02	38.26	39.24	40.70	41.53	42.99	43.76	43.75	44.70	45.76	47.27	48.53	49.70	3.5%
513	35.86	37.17	38.28	39.23	40.63	41.40	42.99	43.75	43.68	44.61	45.66	47.18	48.44	49.61	3.7%
514	28.31	29.28	30.30	31.26	32.04	33.01	33.84	34.78	35.43	36.32	37.11	38.45	39.47	40.47	4.6%
515	32.11	33.31	34.44	35.38	36.48	37.31	38.60	39.50	39.53	40.38	41.28	42.66	43.73	44.76	3.7%
516	19.48	20.30	21.04	21.72	22.31	22.95	23.55	24.04	24.62	24.87	25.40	26.03	26.72	27.28	3.7%
517	9.89	10.22	10.58	10.90	11.23	11.54	11.87	12.10	12.37	12.76	13.22	13.88	14.55	15.17	2.9%
518	7.99	8.22	8.35	8.61	8.77	8.96	9.14	9.34	9.51	9.75	9.97	10.15	10.33	10.49	2.6%
519	2.60	2.66	2.71	2.77	2.82	2.85	2.90	2.93	2.95	2.97	2.99	3.04	3.16	3.25	1.4%
520	2.16	2.22	2.20	2.21	2.22	2.27	2.32	2.38	2.36	2.35	2.38	2.45	2.55	2.70	- -
521	33.20	34.23	35.27	36.25	37.42	38.59	40.00	41.34	42.59	43.78	45.46	47.72	50.26	52.98	2.4%

cesbingbk.d100611a	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Non-Renewable Energy Expenditures by Sector														
(billion nominal dollars)														
Residential	253.79	238.63	249.05	228.20	230.52	232.73	236.03	248.12	254.69	260.73	268.44	275.67	284.55	292.56
Commercial	190.06	174.64	171.15	172.14	171.41	173.13	176.20	187.84	194.13	200.63	208.88	216.54	225.06	233.69
Industrial	247.19	179.30	195.11	218.25	207.73	221.85	231.40	248.92	256.35	265.52	274.98	283.81	295.03	304.86
Transportation	710.71	474.92	559.79	601.29	615.86	662.43	694.37	724.02	758.50	794.65	827.50	854.29	886.96	912.35
Total Non-Renewable Expenditures	1401.75	1067.49	1175.10	1219.88	1225.53	1290.14	1337.99	1408.90	1463.67	1521.52	1579.80	1630.30	1691.59	1743.47
Transportation Renewable Expenditures	0.04	0.06	0.07	0.08	0.14	0.17	0.21	0.25	0.29	3.01	5.72	8.01	10.87	7.28
Total Expenditures	1401.79	1067.55	1175.17	1219.96	1225.66	1290.31	1338.20	1409.15	1463.96	1524.53	1585.53	1638.31	1702.46	1750.75

1/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

2/ Excludes use for lease and plant fuel.

3/ Includes Federal and State taxes while excluding county and local taxes.

4/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for thie forecast.

5/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.

6/ Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.

7/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.

8/ Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.

9/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

10/ Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

- - = Not applicable.

Note: Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), Petroleum Marketing Annual 2009, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 residential and commercial natural gas delivered prices: EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 residential and commercial natural gas delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 and 2009 industrial natural gas delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey and industrial and wellhead prices from the Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the Natural Gas Monthly, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 transportation sector natural gas delivered prices are based on: EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010) and estimated State taxes, Federal taxes, and dispensing costs or charges.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
522															
523															
524															
525	300.58	310.62	321.80	331.17	342.19	353.26	366.16	376.69	388.11	400.39	415.81	433.76	453.29	473.50	2.7%
526	241.58	251.52	261.75	271.48	282.56	293.71	306.73	318.78	330.59	342.40	357.78	377.73	399.34	421.97	3.5%
527	314.30	324.81	334.23	342.97	351.13	358.26	366.67	373.89	380.12	387.85	397.13	410.99	423.81	436.13	3.5%
528	937.94	968.32	994.34	1021.60	1053.66	1087.95	1118.25	1154.75	1170.28	1204.83	1241.50	1294.11	1339.82	1383.44	4.2%
529	1794.40	1855.27	1912.13	1967.22	2029.54	2093.18	2157.80	2224.11	2269.10	2335.47	2412.23	2516.59	2616.26	2715.03	3.7%
530	14.57	21.91	31.10	36.35	43.68	40.46	54.93	50.63	48.34	50.72	52.62	53.30	54.88	56.33	30.3%
531	1808.97	1877.18	1943.23	2003.57	2073.22	2133.64	2212.73	2274.73	2317.45	2386.19	2464.85	2569.89	2671.14	2771.36	3.7%
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
565	2009 transportation sector natural gas delivered prices are model results.														
566	2008 and 2009 electric power prices based on: EIA, Monthly Energy Review, DOE/EIA-0035(2010/09)														
567	(Washington, DC, September 2010). 2008 and 2009 E85 prices														
568	2008 and 2009 electric power sector natural gas prices: EIA, Electric Power Monthly,														
569	April 2009 and April 2010, Table 4.2.														
570	2008 and 2009 coal prices based on: EIA, Quarterly Coal Report,														
571	October-December 2009, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
572	2008 and 2009 electricity prices: EIA, Annual Energy Review														
573	2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).														
574	2008 and 2009 E85 prices derived from monthly prices in the Clean Cities														
575	Alternative Fuel Price Report. Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
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1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
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624															
625	**4. Residential Sector Key Indicators and Consumption**														
626	**(quadrillion Btu, unless otherwise noted)**														
627															
628	*Key Indicators and Consumption*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
629															
630	**Key Indicators**														
631	**Households (millions)**														
632	Single-Family	80.95	81.48	82.56	83.80	84.81	85.90	86.90	87.90	88.90	89.87	90.82	91.75	92.67	93.55
633	Multifamily	25.12	25.32	25.57	25.86	26.07	26.33	26.59	26.88	27.19	27.53	27.88	28.25	28.63	29.02
634	Mobile Homes	6.69	6.63	6.60	6.56	6.54	6.53	6.52	6.53	6.57	6.61	6.67	6.72	6.78	6.83
635	**Total**	**112.76**	**113.43**	**114.74**	**116.22**	**117.42**	**118.76**	**120.01**	**121.31**	**122.66**	**124.02**	**125.37**	**126.73**	**128.07**	**129.40**
636															
637	**Average House Square Footage**	**1656**	**1669**	**1686**	**1704**	**1720**	**1735**	**1750**	**1765**	**1779**	**1793**	**1806**	**1819**	**1831**	**1843**
638															
639	**Energy Intensity**														
640	**(million Btu per household)**														
641	Delivered Energy Consumption	100.8	98.0	99.7	95.5	94.7	93.2	92.2	90.7	89.7	88.5	87.8	87.1	86.5	85.6
642	Total Energy Consumption	191.0	185.8	192.3	180.3	178.8	174.5	172.2	167.2	165.8	164.0	162.6	161.3	160.3	158.6
643	**(thousand Btu per square foot)**														
644	Delivered Energy Consumption	60.9	58.7	59.1	56.1	55.1	53.7	52.7	51.4	50.4	49.4	48.6	47.9	47.2	46.4

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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627															**2009-**
628	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
629															
630															
631															
632	94.45	95.33	96.20	97.09	97.96	98.81	99.61	100.38	101.14	101.89	102.60	103.29	103.98	104.66	1.0%
633	29.43	29.84	30.25	30.67	31.08	31.50	31.92	32.33	32.74	33.15	33.56	33.97	34.38	34.78	1.2%
634	6.89	6.94	6.99	7.04	7.08	7.13	7.17	7.21	7.25	7.29	7.32	7.35	7.38	7.40	0.4%
635	**130.76**	**132.11**	**133.44**	**134.79**	**136.13**	**137.44**	**138.70**	**139.92**	**141.14**	**142.33**	**143.49**	**144.61**	**145.73**	**146.84**	**1.0%**
636															
637	**1855**	**1866**	**1877**	**1888**	**1899**	**1909**	**1919**	**1928**	**1938**	**1947**	**1956**	**1964**	**1973**	**1981**	**0.7%**
638															
639															
640															
641	85.0	84.3	83.9	83.1	82.6	82.0	81.7	81.0	80.5	80.0	79.6	78.8	78.2	77.6	-0.9%
642	157.3	156.1	155.3	154.0	153.1	152.3	151.9	151.0	150.3	149.1	148.4	146.7	145.3	143.9	-1.0%
643															
644	45.8	45.2	44.7	44.0	43.5	43.0	42.6	42.0	41.5	41.1	40.7	40.1	39.6	39.2	-1.5%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
645	Total Energy Consumption	115.3	111.3	114.0	105.8	104.0	100.5	98.4	94.7	93.2	91.4	90.0	88.7	87.5	86.0
646															
647	**Delivered Energy Consumption by Fuel**														
648	**Purchased Electricity**														
649	Space Heating	0.28	0.28	0.29	0.28	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.30	0.30
650	Space Cooling	0.87	0.83	1.11	0.80	0.81	0.82	0.83	0.82	0.82	0.83	0.83	0.84	0.85	0.86
651	Water Heating	0.43	0.43	0.44	0.44	0.46	0.46	0.47	0.47	0.48	0.48	0.48	0.49	0.49	0.49
652	Refrigeration	0.37	0.37	0.36	0.36	0.36	0.36	0.36	0.35	0.35	0.35	0.35	0.35	0.35	0.35
653	Cooking	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.13
654	Clothes Dryers	0.19	0.19	0.19	0.18	0.19	0.19	0.19	0.18	0.18	0.18	0.18	0.18	0.18	0.18
655	Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
656	Lighting	0.72	0.71	0.71	0.70	0.69	0.62	0.59	0.57	0.56	0.56	0.55	0.55	0.54	0.53
657	Clothes Washers 1/	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
658	Dishwashers 1/	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
659	Color Televisions and Set-Top Boxes	0.33	0.34	0.34	0.34	0.34	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.34
660	Personal Computers and Related Equipn	0.17	0.18	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
661	Furnace Fans and Boiler Circulation Pum	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17
662	Other Uses 2/	0.89	0.88	0.90	0.89	0.91	0.92	0.93	0.95	0.97	0.98	1.00	1.02	1.05	1.07
663	**Delivered Energy**	**4.71**	**4.65**	**4.97**	**4.63**	**4.67**	**4.62**	**4.61**	**4.60**	**4.63**	**4.64**	**4.67**	**4.71**	**4.74**	**4.77**
664															
665	**Natural Gas**														
666	Space Heating	3.40	3.28	3.29	3.25	3.26	3.28	3.29	3.27	3.26	3.24	3.24	3.24	3.25	3.24
667	Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
668	Water Heating	1.33	1.33	1.34	1.36	1.38	1.38	1.39	1.38	1.37	1.37	1.37	1.38	1.38	1.38
669	Cooking	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.23	0.23
670	Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
671	**Delivered Energy**	**5.00**	**4.87**	**4.90**	**4.89**	**4.91**	**4.94**	**4.96**	**4.92**	**4.91**	**4.88**	**4.89**	**4.90**	**4.91**	**4.90**
672															
673	**Distillate Fuel Oil**														
674	Space Heating	0.56	0.50	0.50	0.53	0.50	0.50	0.49	0.48	0.47	0.46	0.45	0.44	0.43	0.42
675	Water Heating	0.11	0.10	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07	0.06	0.06
676	**Delivered Energy**	**0.66**	**0.61**	**0.60**	**0.62**	**0.59**	**0.58**	**0.57**	**0.56**	**0.55**	**0.53**	**0.52**	**0.51**	**0.50**	**0.48**
677															
678	**Liquefied Petroleum Gases**														
679	Space Heating	0.26	0.26	0.26	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.22	0.22	0.22
680	Water Heating	0.09	0.08	0.08	0.07	0.07	0.07	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05
681	Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
682	Other Uses 3/	0.14	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.19
683	**Delivered Energy**	**0.52**	**0.53**	**0.52**	**0.51**	**0.50**	**0.50**	**0.49**	**0.49**	**0.49**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
645	84.8	83.6	82.7	81.6	80.7	79.8	79.2	78.3	77.6	76.6	75.9	74.7	73.7	72.6	-1.6%
646															
647															
648															
649	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.29	0.29	0.1%
650	0.86	0.87	0.88	0.88	0.89	0.90	0.90	0.91	0.92	0.93	0.93	0.94	0.94	0.94	0.5%
651	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.48	0.48	0.47	0.47	0.46	0.46	0.45	0.2%
652	0.35	0.35	0.35	0.35	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.37	0.38	0.38	0.1%
653	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	1.3%
654	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.1%
655	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.4%
656	0.52	0.52	0.52	0.52	0.52	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	-1.3%
657	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.4%
658	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.8%
659	0.34	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.38	0.38	0.39	0.39	0.39	0.39	0.6%
660	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.3%
661	0.17	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	1.3%
662	1.09	1.11	1.14	1.16	1.18	1.20	1.22	1.23	1.26	1.27	1.29	1.30	1.32	1.33	1.6%
663	**4.81**	**4.85**	**4.90**	**4.93**	**4.97**	**5.01**	**5.05**	**5.08**	**5.12**	**5.16**	**5.20**	**5.21**	**5.23**	**5.25**	**0.5%**
664															
665															
666	3.24	3.25	3.26	3.25	3.25	3.26	3.27	3.26	3.27	3.27	3.27	3.26	3.25	3.24	0.0%
667	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
668	1.38	1.38	1.38	1.38	1.38	1.38	1.37	1.37	1.36	1.35	1.34	1.33	1.32	1.31	0.0%
669	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.5%
670	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.3%
671	**4.90**	**4.91**	**4.92**	**4.91**	**4.92**	**4.92**	**4.93**	**4.92**	**4.92**	**4.91**	**4.91**	**4.88**	**4.86**	**4.85**	**0.0%**
672															
673															
674	0.41	0.41	0.40	0.39	0.38	0.37	0.37	0.36	0.36	0.35	0.35	0.34	0.33	0.33	-1.7%
675	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	-3.4%
676	**0.47**	**0.46**	**0.45**	**0.44**	**0.43**	**0.43**	**0.42**	**0.41**	**0.40**	**0.40**	**0.39**	**0.38**	**0.38**	**0.37**	**-1.9%**
677															
678															
679	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.19	-1.1%
680	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	-3.5%
681	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.7%
682	0.19	0.19	0.19	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.23	1.5%
683	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**0.48**	**-0.4%**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
684															
685	Marketed Renewables (wood) 4/	0.44	0.43	0.42	0.42	0.41	0.40	0.40	0.40	0.41	0.41	0.41	0.42	0.42	0.42
686	Other Fuels 5/	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
687															
688	**Delivered Energy Consumption by End Use**														
689	Space Heating	4.97	4.78	4.78	4.76	4.72	4.73	4.73	4.70	4.68	4.65	4.64	4.64	4.64	4.62
690	Space Cooling	0.87	0.83	1.11	0.80	0.81	0.82	0.83	0.82	0.82	0.83	0.83	0.84	0.85	0.86
691	Water Heating	1.96	1.95	1.96	1.97	1.99	2.00	2.00	1.99	1.98	1.97	1.98	1.98	1.98	1.98
692	Refrigeration	0.37	0.37	0.36	0.36	0.36	0.36	0.36	0.35	0.35	0.35	0.35	0.35	0.35	0.35
693	Cooking	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.37	0.37	0.37	0.37	0.38	0.38
694	Clothes Dryers	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23
695	Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
696	Lighting	0.72	0.71	0.71	0.70	0.69	0.62	0.59	0.57	0.56	0.56	0.55	0.55	0.54	0.53
697	Clothes Washers 1/	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
698	Dishwashers 1/	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
699	Color Televisions and Set-Top Boxes	0.33	0.34	0.34	0.34	0.34	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.34
700	Personal Computers and Related Equipm	0.17	0.18	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
701	Furnace Fans and Boiler Circulation Pump	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17
702	Other Uses 6/	1.03	1.03	1.06	1.05	1.07	1.08	1.10	1.12	1.14	1.16	1.18	1.20	1.23	1.25
703	**Delivered Energy**	**11.36**	**11.12**	**11.44**	**11.10**	**11.12**	**11.07**	**11.06**	**11.01**	**11.00**	**10.98**	**11.00**	**11.04**	**11.08**	**11.08**
704															
705	**Electricity Related Losses**	**10.17**	**9.95**	**10.62**	**9.85**	**9.87**	**9.66**	**9.60**	**9.27**	**9.34**	**9.36**	**9.38**	**9.41**	**9.45**	**9.45**
706															
707	**Total Energy Consumption by End Use**														
708	Space Heating	5.59	5.39	5.40	5.35	5.31	5.32	5.32	5.27	5.26	5.23	5.23	5.22	5.23	5.21
709	Space Cooling	2.75	2.62	3.50	2.50	2.53	2.54	2.54	2.48	2.48	2.50	2.51	2.52	2.54	2.55
710	Water Heating	2.89	2.88	2.90	2.92	2.96	2.97	2.98	2.94	2.95	2.94	2.94	2.95	2.96	2.95
711	Refrigeration	1.18	1.15	1.14	1.13	1.13	1.11	1.10	1.06	1.06	1.05	1.04	1.04	1.04	1.03
712	Cooking	0.58	0.58	0.58	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61	0.62	0.62	0.63
713	Clothes Dryers	0.65	0.64	0.64	0.63	0.63	0.63	0.63	0.61	0.61	0.60	0.60	0.59	0.59	0.59
714	Freezers	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
715	Lighting	2.28	2.23	2.22	2.18	2.16	1.90	1.80	1.72	1.70	1.68	1.67	1.66	1.61	1.57
716	Clothes Washers 1/	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08
717	Dishwashers 1/	0.29	0.29	0.28	0.28	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.28	0.28	0.28
718	Color Televisions and Set-Top Boxes	1.05	1.05	1.07	1.06	1.06	1.04	1.03	1.00	1.00	1.00	1.00	1.00	1.01	1.01
719	Personal Computers and Related Equipm	0.55	0.56	0.56	0.57	0.55	0.53	0.53	0.51	0.51	0.51	0.51	0.51	0.52	0.52
720	Furnace Fans and Boiler Circulation Pump	0.43	0.44	0.44	0.45	0.46	0.46	0.47	0.46	0.47	0.48	0.48	0.49	0.49	0.51
721	Other Uses 6/	2.94	2.91	2.99	2.94	2.98	3.00	3.04	3.03	3.09	3.14	3.20	3.25	3.32	3.37
722	**Total**	**21.53**	**21.07**	**22.06**	**20.95**	**20.99**	**20.72**	**20.66**	**20.28**	**20.34**	**20.33**	**20.38**	**20.45**	**20.53**	**20.52**

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
684															
685	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.42	0.42	0.42	0.42	0.42	0.42	0.42	-0.1%
686	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-1.4%
687															
688															
689	4.61	4.61	4.61	4.59	4.59	4.58	4.59	4.57	4.57	4.56	4.56	4.53	4.51	4.50	-0.2%
690	0.86	0.87	0.88	0.88	0.89	0.90	0.90	0.91	0.92	0.93	0.93	0.94	0.94	0.94	0.5%
691	1.98	1.98	1.98	1.97	1.96	1.95	1.95	1.93	1.92	1.90	1.89	1.87	1.85	1.84	-0.2%
692	0.35	0.35	0.35	0.35	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.37	0.38	0.38	0.1%
693	0.38	0.38	0.39	0.39	0.39	0.39	0.40	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.6%
694	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.1%
695	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.4%
696	0.52	0.52	0.52	0.52	0.52	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	-1.3%
697	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.4%
698	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.8%
699	0.34	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.38	0.38	0.39	0.39	0.39	0.39	0.6%
700	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.3%
701	0.17	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	1.3%
702	1.28	1.30	1.33	1.35	1.38	1.40	1.43	1.44	1.47	1.49	1.51	1.53	1.54	1.56	1.6%
703	**11.11**	**11.14**	**11.20**	**11.21**	**11.24**	**11.27**	**11.33**	**11.33**	**11.36**	**11.38**	**11.43**	**11.40**	**11.39**	**11.40**	**0.1%**
704															
705	**9.45**	**9.47**	**9.52**	**9.55**	**9.61**	**9.66**	**9.74**	**9.80**	**9.86**	**9.84**	**9.87**	**9.81**	**9.79**	**9.73**	**-0.1%**
706															
707															
708	5.20	5.19	5.19	5.17	5.17	5.16	5.17	5.15	5.14	5.13	5.13	5.09	5.06	5.04	-0.3%
709	2.56	2.57	2.58	2.60	2.61	2.63	2.65	2.67	2.68	2.69	2.70	2.70	2.70	2.68	0.1%
710	2.94	2.94	2.94	2.92	2.91	2.89	2.89	2.86	2.84	2.80	2.78	2.74	2.71	2.68	-0.3%
711	1.02	1.02	1.03	1.03	1.03	1.04	1.05	1.06	1.06	1.07	1.08	1.08	1.08	1.09	-0.2%
712	0.63	0.63	0.64	0.64	0.65	0.65	0.66	0.67	0.67	0.67	0.68	0.68	0.68	0.69	0.7%
713	0.58	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.60	0.60	0.59	-0.3%
714	0.24	0.24	0.24	0.24	0.24	0.24	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.0%
715	1.55	1.54	1.53	1.52	1.51	1.51	1.51	1.50	1.50	1.49	1.49	1.48	1.47	1.45	-1.6%
716	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.8%
717	0.28	0.28	0.29	0.29	0.29	0.30	0.30	0.31	0.31	0.31	0.32	0.32	0.32	0.32	0.5%
718	1.02	1.03	1.04	1.04	1.05	1.06	1.08	1.09	1.10	1.11	1.12	1.12	1.12	1.12	0.2%
719	0.52	0.52	0.52	0.52	0.53	0.53	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55	-0.1%
720	0.51	0.52	0.52	0.53	0.53	0.54	0.54	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.9%
721	3.43	3.48	3.54	3.59	3.65	3.71	3.78	3.83	3.89	3.92	3.97	3.98	4.01	4.02	1.3%
722	**20.56**	**20.62**	**20.72**	**20.76**	**20.85**	**20.93**	**21.07**	**21.13**	**21.22**	**21.23**	**21.29**	**21.21**	**21.18**	**21.12**	**0.0%**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
723															
724	**Nonmarketed Renewables 7/**														
725	Geothermal Heat Pumps	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
726	Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
727	Solar Photovoltaic	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
728	Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
729	**Total**	**0.01**	**0.01**	**0.02**	**0.03**	**0.04**	**0.05**	**0.06**	**0.07**	**0.08**	**0.08**	**0.08**	**0.08**	**0.09**	**0.09**

734 1/ Does not include water heating portion of load.
735 2/ Includes small electric devices, heating elements, and motors not listed above.
736 3/ Includes such appliances as outdoor grills and mosquito traps.
737 4/ Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the Residential Energy Consumption
738 Survey 2005.
739 5/ Includes kerosene and coal.
740 6/ Includes all other uses listed above.
741 7/ Represents delivered energy displaced.
742 Btu = British thermal unit.
743 - - = Not applicable.
744 Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009
745 are model results and may differ slightly from official EIA data reports.
746 Source: 2008 and 2009 based on: U.S. Energy Information Administration (EIA), Annual Energy
747 Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010). Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
723															
724															
725	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	8.7%
726	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2.1%
727	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	9.9%
728	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	11.1%
729	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.11**	**0.11**	**0.11**	**8.4%**
730															
731															
732															
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
764															
765															
766															
767															
768															
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791															
792															
793															
794															
795															
796															
797															
798															
799															
800	**5. Commercial Sector Key Indicators and Consumption**														
801	**(quadrillion Btu, unless otherwise noted)**														
802															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
764															
765															
766															
767															
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795															
796															
797															
798															
799															
800															
801															
802															**2009-**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
803	*Key Indicators and Consumption*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
804															
805	**Key Indicators**														
806															
807	**Total Floorspace (billion square feet)**														
808	Surviving	76.4	77.9	79.2	80.3	81.1	81.8	82.6	83.4	84.5	85.6	86.8	88.0	89.2	90.3
809	New Additions	2.4	2.3	2.0	1.7	1.7	1.7	1.8	2.0	2.1	2.2	2.2	2.2	2.2	2.2
810	**Total**	**78.8**	**80.2**	**81.2**	**82.0**	**82.7**	**83.5**	**84.4**	**85.5**	**86.6**	**87.8**	**89.0**	**90.2**	**91.4**	**92.5**
811															
812	**Energy Consumption Intensity**														
813	**(thousand Btu per square foot)**														
814	Delivered Energy Consumption	109.1	105.9	104.8	105.6	105.6	105.7	106.1	105.4	104.5	104.0	103.6	103.3	102.8	102.3
815	Electricity Related Losses	125.0	120.6	121.3	120.0	119.3	118.2	118.0	114.2	114.5	114.4	114.0	113.5	113.2	112.5
816	Total Energy Consumption	234.1	226.4	226.0	225.5	224.9	224.0	224.0	219.6	219.0	218.4	217.6	216.8	216.0	214.8
817															
818	**Delivered Energy Consumption by Fuel**														
819															
820	**Purchased Electricity**														
821	Space Heating 1/	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
822	Space Cooling 1/	0.49	0.47	0.58	0.51	0.52	0.52	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.54
823	Water Heating 1/	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
824	Ventilation	0.50	0.50	0.51	0.52	0.53	0.54	0.55	0.56	0.57	0.58	0.58	0.59	0.60	0.61
825	Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
826	Lighting	1.04	1.03	1.02	1.03	1.03	1.03	1.04	1.04	1.05	1.06	1.07	1.08	1.09	1.10
827	Refrigeration	0.40	0.40	0.39	0.39	0.38	0.37	0.37	0.36	0.36	0.36	0.36	0.36	0.36	0.36
828	Office Equipment (PC)	0.22	0.22	0.21	0.20	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
829	Office Equipment (non-PC)	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.32	0.33	0.34	0.35	0.36	0.37	0.37
830	Other Uses 2/	1.37	1.35	1.33	1.41	1.45	1.48	1.52	1.56	1.60	1.64	1.68	1.72	1.77	1.81
831	**Delivered Energy**	**4.56**	**4.51**	**4.60**	**4.63**	**4.67**	**4.72**	**4.78**	**4.85**	**4.91**	**4.98**	**5.06**	**5.13**	**5.20**	**5.26**
832															
833	**Natural Gas**														
834	Space Heating 1/	1.56	1.61	1.62	1.65	1.66	1.68	1.71	1.70	1.69	1.69	1.70	1.71	1.71	1.70
835	Space Cooling 1/	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
836	Water Heating 1/	0.44	0.45	0.46	0.47	0.48	0.49	0.51	0.51	0.51	0.52	0.53	0.53	0.54	0.55
837	Cooking	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21
838	Other Uses 3/	1.02	0.94	0.88	0.96	0.97	0.98	1.00	0.99	0.99	0.98	0.99	0.99	1.00	1.00
839	**Delivered Energy**	**3.22**	**3.20**	**3.18**	**3.31**	**3.34**	**3.39**	**3.45**	**3.44**	**3.42**	**3.43**	**3.45**	**3.48**	**3.49**	**3.50**
840															
841	**Distillate Fuel Oil**														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
803	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
804															
805															
806															
807															
808	91.5	92.6	93.8	95.0	96.2	97.4	98.6	99.8	101.1	102.3	103.5	104.7	106.0	107.2	1.2%
809	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	0.4%
810	**93.7**	**94.9**	**96.1**	**97.3**	**98.5**	**99.8**	**101.0**	**102.2**	**103.5**	**104.7**	**105.9**	**107.2**	**108.4**	**109.7**	**1.2%**
811															
812															
813															
814	101.8	101.4	101.0	100.7	100.4	100.1	99.8	99.6	99.4	99.2	99.0	98.6	98.2	97.7	-0.3%
815	111.7	111.0	110.4	110.2	110.0	109.7	109.5	109.6	109.3	108.3	107.6	106.5	105.4	103.8	-0.6%
816	213.5	212.5	211.5	210.9	210.4	209.8	209.3	209.1	208.7	207.6	206.7	205.1	203.6	201.5	-0.4%
817															
818															
819															
820															
821	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	-0.3%
822	0.54	0.54	0.55	0.55	0.55	0.55	0.56	0.56	0.56	0.57	0.57	0.58	0.58	0.58	0.8%
823	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	-0.2%
824	0.62	0.62	0.63	0.63	0.64	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.65	0.65	1.0%
825	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.2%
826	1.10	1.11	1.12	1.13	1.13	1.14	1.14	1.15	1.15	1.16	1.17	1.17	1.16	1.16	0.4%
827	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.37	0.37	0.37	0.37	0.38	0.38	0.38	-0.2%
828	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21	-0.1%
829	0.38	0.39	0.39	0.40	0.41	0.42	0.43	0.43	0.44	0.44	0.45	0.45	0.46	0.46	2.4%
830	1.85	1.89	1.93	1.98	2.02	2.07	2.11	2.16	2.21	2.26	2.30	2.35	2.39	2.43	2.3%
831	**5.33**	**5.39**	**5.46**	**5.53**	**5.60**	**5.67**	**5.74**	**5.80**	**5.87**	**5.94**	**6.01**	**6.06**	**6.11**	**6.14**	**1.2%**
832															
833															
834	1.70	1.71	1.71	1.71	1.71	1.71	1.72	1.72	1.72	1.73	1.73	1.72	1.71	1.70	0.2%
835	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.5%
836	0.55	0.56	0.57	0.57	0.58	0.58	0.59	0.60	0.60	0.61	0.61	0.61	0.62	0.62	1.2%
837	0.21	0.21	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	1.3%
838	1.01	1.01	1.02	1.03	1.04	1.06	1.07	1.09	1.12	1.14	1.17	1.20	1.23	1.27	1.2%
839	**3.51**	**3.53**	**3.54**	**3.56**	**3.59**	**3.61**	**3.64**	**3.67**	**3.71**	**3.74**	**3.78**	**3.81**	**3.83**	**3.87**	**0.7%**
840															
841															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
842	Space Heating 1/	0.15	0.16	0.14	0.15	0.14	0.14	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12
843	Water Heating 1/	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
844	Other Uses 4/	0.20	0.16	0.17	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
845	**Delivered Energy**	**0.37**	**0.34**	**0.32**	**0.30**	**0.29**	**0.29**	**0.29**	**0.28**	**0.28**	**0.28**	**0.27**	**0.27**	**0.27**	**0.26**
846															
847	Marketed Renewables (biomass)	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
848	Other Fuels 5/	0.34	0.33	0.29	0.31	0.33	0.32	0.32	0.33	0.33	0.33	0.33	0.33	0.33	0.33
849															
850	**Delivered Energy Consumption by End Use**														
851	Space Heating 1/	1.89	1.94	1.93	1.97	1.97	1.99	2.02	2.00	1.99	1.99	2.00	2.00	2.00	2.00
852	Space Cooling 1/	0.52	0.51	0.62	0.55	0.56	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.57	0.57
853	Water Heating 1/	0.55	0.56	0.57	0.58	0.59	0.60	0.62	0.62	0.62	0.63	0.64	0.65	0.65	0.66
854	Ventilation	0.50	0.50	0.51	0.52	0.53	0.54	0.55	0.56	0.57	0.58	0.58	0.59	0.60	0.61
855	Cooking	0.19	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.23
856	Lighting	1.04	1.03	1.02	1.03	1.03	1.03	1.04	1.04	1.05	1.06	1.07	1.08	1.09	1.10
857	Refrigeration	0.40	0.40	0.39	0.39	0.38	0.37	0.37	0.36	0.36	0.36	0.36	0.36	0.36	0.36
858	Office Equipment (PC)	0.22	0.22	0.21	0.20	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
859	Office Equipment (non-PC)	0.24	0.25	0.26	0.27	0.28	0.29	0.30	0.32	0.33	0.34	0.35	0.36	0.37	0.37
860	Other Uses 6/	3.04	2.89	2.78	2.94	2.99	3.03	3.08	3.12	3.15	3.19	3.24	3.29	3.33	3.38
861	**Delivered Energy**	**8.60**	**8.49**	**8.51**	**8.66**	**8.74**	**8.83**	**8.95**	**9.00**	**9.05**	**9.13**	**9.22**	**9.32**	**9.39**	**9.47**
862															
863	**Electricity Related Losses**	**9.85**	**9.66**	**9.85**	**9.84**	**9.87**	**9.87**	**9.96**	**9.76**	**9.91**	**10.04**	**10.14**	**10.24**	**10.35**	**10.41**
864															
865	**Total Energy Consumption by End Use**														
866	Space Heating 1/	2.28	2.32	2.31	2.34	2.33	2.35	2.37	2.35	2.34	2.34	2.34	2.35	2.35	2.34
867	Space Cooling 1/	1.58	1.52	1.87	1.64	1.65	1.65	1.66	1.63	1.63	1.63	1.63	1.63	1.64	1.64
868	Water Heating 1/	0.75	0.76	0.76	0.78	0.79	0.80	0.82	0.81	0.81	0.82	0.83	0.83	0.84	0.85
869	Ventilation	1.57	1.58	1.60	1.63	1.66	1.68	1.70	1.69	1.71	1.74	1.76	1.78	1.80	1.81
870	Cooking	0.24	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.27	0.27	0.27	0.28	0.28	0.28
871	Lighting	3.29	3.24	3.21	3.20	3.21	3.19	3.20	3.15	3.17	3.20	3.22	3.24	3.26	3.27
872	Refrigeration	1.28	1.25	1.23	1.21	1.18	1.15	1.14	1.10	1.09	1.08	1.08	1.07	1.07	1.06
873	Office Equipment (PC)	0.70	0.68	0.66	0.64	0.61	0.59	0.58	0.57	0.57	0.57	0.57	0.57	0.57	0.57
874	Office Equipment (non-PC)	0.75	0.78	0.82	0.85	0.87	0.90	0.93	0.95	0.99	1.03	1.06	1.08	1.10	1.11
875	Other Uses 6/	6.00	5.77	5.63	5.94	6.05	6.13	6.24	6.25	6.38	6.50	6.61	6.73	6.85	6.96
876	**Total**	**18.44**	**18.15**	**18.35**	**18.49**	**18.61**	**18.70**	**18.91**	**18.76**	**18.97**	**19.17**	**19.36**	**19.56**	**19.74**	**19.88**
877															
878	**Nonmarketed Renewable Fuels 7/**														
879	Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
880	Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
842	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	-1.6%
843	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
844	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	-1.0%
845	**0.26**	**0.26**	**0.26**	**0.26**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**-1.2%**
846															
847	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
848	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.35	0.2%
849															
850															
851	2.00	2.00	1.99	1.99	2.00	2.00	2.00	2.00	2.00	2.00	2.00	1.99	1.98	1.97	0.1%
852	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.59	0.60	0.60	0.61	0.61	0.61	0.61	0.7%
853	0.66	0.67	0.68	0.68	0.69	0.69	0.70	0.71	0.71	0.72	0.72	0.72	0.72	0.72	1.0%
854	0.62	0.62	0.63	0.63	0.64	0.64	0.64	0.65	0.65	0.65	0.65	0.65	0.65	0.65	1.0%
855	0.23	0.24	0.24	0.24	0.24	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.26	1.1%
856	1.10	1.11	1.12	1.13	1.13	1.14	1.14	1.15	1.15	1.16	1.17	1.17	1.16	1.16	0.4%
857	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.37	0.37	0.37	0.37	0.38	0.38	0.38	-0.2%
858	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21	0.21	-0.1%
859	0.38	0.39	0.39	0.40	0.41	0.42	0.43	0.43	0.44	0.44	0.45	0.45	0.46	0.46	2.4%
860	3.43	3.48	3.53	3.58	3.64	3.70	3.76	3.83	3.90	3.98	4.05	4.13	4.21	4.29	1.5%
861	**9.54**	**9.62**	**9.71**	**9.80**	**9.89**	**9.98**	**10.08**	**10.18**	**10.28**	**10.39**	**10.49**	**10.57**	**10.64**	**10.72**	**0.9%**
862															
863	**10.46**	**10.54**	**10.61**	**10.72**	**10.84**	**10.95**	**11.06**	**11.20**	**11.31**	**11.34**	**11.41**	**11.42**	**11.43**	**11.39**	**0.6%**
864															
865															
866	2.34	2.34	2.33	2.33	2.33	2.33	2.33	2.34	2.34	2.33	2.33	2.31	2.30	2.28	-0.1%
867	1.64	1.64	1.64	1.65	1.65	1.66	1.66	1.67	1.68	1.68	1.69	1.70	1.69	1.68	0.4%
868	0.85	0.85	0.86	0.86	0.87	0.87	0.88	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.6%
869	1.82	1.83	1.84	1.86	1.87	1.88	1.88	1.90	1.90	1.90	1.90	1.89	1.87	1.85	0.6%
870	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.30	0.30	0.30	0.30	0.30	0.30	0.8%
871	3.27	3.28	3.29	3.31	3.32	3.34	3.35	3.37	3.38	3.38	3.38	3.36	3.34	3.31	0.1%
872	1.06	1.05	1.05	1.05	1.06	1.06	1.07	1.07	1.08	1.08	1.08	1.08	1.08	1.08	-0.6%
873	0.56	0.56	0.57	0.57	0.58	0.58	0.59	0.59	0.60	0.60	0.60	0.60	0.60	0.59	-0.5%
874	1.13	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.29	1.30	1.31	1.31	1.32	2.0%
875	7.06	7.17	7.29	7.42	7.56	7.69	7.84	8.00	8.15	8.28	8.42	8.55	8.68	8.80	1.6%
876	**20.01**	**20.16**	**20.32**	**20.52**	**20.73**	**20.93**	**21.14**	**21.38**	**21.59**	**21.73**	**21.89**	**21.99**	**22.07**	**22.10**	**0.8%**
877															
878															
879	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.8%
880	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	4.6%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
881	Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
882	**Total**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

1/ Includes fuel consumption for district services.
2/ Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
3/ Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
4/ Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
5/ Includes residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
6/ Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
7/ Represents delivered energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Source: 2008 and 2009 based on: U.S. Energy Information Administration (EIA), Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010). Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
881	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.0%
882	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**1.6%**
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
923															
924															
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950	**6. Industrial Sector Key Indicators and Consumption**														
951															
952															
953	*Shipments, Prices, and Consumption*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
954															
955	**Value of Shipments**														
956	**(billion 2005 dollars)**														
957	Manufacturing	4680	4197	4451	4716	4919	5200	5230	5239	5248	5310	5387	5471	5557	5633
958	Agriculture, Mining, and Construction	2039	1821	1793	1845	1979	2094	2147	2206	2241	2263	2286	2313	2337	2349
959	**Total**	**6720**	**6017**	**6244**	**6562**	**6898**	**7294**	**7377**	**7445**	**7488**	**7573**	**7673**	**7784**	**7894**	**7982**
960															
961	**Energy Prices**														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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950															
951															
952															**2009-**
953	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
954															
955															
956															
957	5704	5781	5859	5944	6017	6091	6158	6233	6322	6401	6466	6538	6606	6671	1.8%
958	2371	2389	2397	2419	2439	2450	2452	2456	2475	2496	2514	2532	2563	2583	1.4%
959	**8075**	**8170**	**8256**	**8363**	**8455**	**8541**	**8610**	**8689**	**8797**	**8897**	**8981**	**9070**	**9169**	**9254**	**1.7%**
960															
961															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
962	**(2009 dollars per million Btu)**														
963	Liquefied Petroleum Gases	24.95	20.59	22.10	27.91	22.06	22.57	23.00	23.14	23.51	24.06	24.61	25.10	25.55	25.97
964	Motor Gasoline	16.48	16.59	19.78	21.97	23.31	24.57	25.35	25.92	26.41	27.04	27.47	27.71	28.17	28.19
965	Distillate Fuel Oil	22.57	16.56	18.90	19.79	18.09	18.49	18.89	19.28	20.04	20.78	21.48	21.88	22.34	22.67
966	Residual Fuel Oil	16.26	12.05	12.32	13.35	13.59	13.91	14.38	14.76	15.20	15.58	16.01	16.28	16.66	16.91
967	Asphalt and Road Oil	8.35	6.52	6.68	7.24	6.83	6.98	7.21	7.38	7.62	7.83	8.04	8.18	8.37	8.51
968	Natural Gas Heat and Power	8.17	4.48	4.03	4.08	3.93	3.89	3.88	4.91	5.07	5.10	5.14	5.18	5.36	5.53
969	Natural Gas Feedstock	9.86	6.03	5.56	5.60	5.49	5.47	5.46	6.50	6.63	6.66	6.69	6.72	6.90	7.04
970	Metallurgical Coal	4.53	5.43	6.19	6.10	6.07	6.14	6.02	5.99	5.83	6.10	6.16	6.28	6.35	6.40
971	Other Industrial Coal	2.93	3.05	3.06	3.01	2.98	2.98	2.94	2.86	2.76	2.87	2.84	2.83	2.81	2.82
972	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	1.76	1.73	1.76	1.77	1.78	1.79	1.81
973	Electricity	19.97	19.79	18.89	17.87	17.61	17.32	17.22	17.58	17.62	17.53	17.63	17.72	17.81	18.03
974	**(nominal dollars per million Btu)**														
975	Liquefied Petroleum Gases	24.72	20.59	22.29	28.53	22.82	23.75	24.64	25.31	26.23	27.42	28.63	29.79	30.92	32.00
976	Motor Gasoline	16.33	16.59	19.95	22.46	24.11	25.85	27.16	28.35	29.47	30.81	31.96	32.88	34.09	34.74
977	Distillate Fuel Oil	22.36	16.56	19.06	20.23	18.71	19.46	20.24	21.08	22.36	23.68	24.99	25.96	27.04	27.93
978	Residual Fuel Oil	16.11	12.05	12.42	13.65	14.06	14.64	15.40	16.14	16.96	17.75	18.64	19.32	20.17	20.84
979	Asphalt and Road Oil	8.27	6.52	6.73	7.40	7.06	7.35	7.72	8.07	8.50	8.92	9.35	9.71	10.13	10.49
980	Natural Gas Heat and Power	8.10	4.48	4.07	4.17	4.06	4.09	4.15	5.37	5.65	5.82	5.98	6.15	6.49	6.81
981	Natural Gas Feedstock	9.77	6.03	5.60	5.72	5.68	5.76	5.85	7.10	7.40	7.59	7.78	7.97	8.36	8.68
982	Metallurgical Coal	4.49	5.43	6.24	6.23	6.28	6.46	6.45	6.55	6.51	6.95	7.16	7.46	7.69	7.88
983	Other Industrial Coal	2.90	3.05	3.09	3.08	3.08	3.13	3.15	3.13	3.08	3.27	3.30	3.35	3.40	3.48
984	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	1.92	1.93	2.01	2.07	2.11	2.17	2.23
985	Electricity	19.79	19.79	19.06	18.27	18.22	18.23	18.45	19.23	19.66	19.98	20.51	21.02	21.56	22.22
986															
987															
988	**Energy Consumption 1/ (quadrillion Btu)**														
989	**Industrial Consumption Excluding Refining**														
990	Liquefied Petroleum Gases Heat and Po	0.23	0.21	0.20	0.23	0.24	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
991	Liquefied Petroleum Gases Feedstocks	1.85	1.79	1.92	1.96	1.98	2.03	2.06	2.04	2.02	2.01	2.01	2.01	2.01	2.01
992	Motor Gasoline	0.25	0.25	0.25	0.27	0.29	0.31	0.32	0.33	0.33	0.33	0.33	0.33	0.33	0.33
993	Distillate Fuel Oil	1.26	1.16	1.19	1.19	1.22	1.24	1.20	1.15	1.16	1.16	1.16	1.16	1.16	1.16
994	Residual Fuel Oil	0.19	0.16	0.17	0.17	0.17	0.17	0.17	0.18	0.17	0.17	0.17	0.17	0.17	0.17
995	Petrochemical Feedstocks	1.12	0.90	0.97	1.06	1.10	1.18	1.24	1.27	1.26	1.26	1.26	1.26	1.27	1.27
996	Petroleum Coke	0.35	0.28	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.22	0.22	0.22	0.22
997	Asphalt and Road Oil	1.01	0.87	0.85	0.90	1.00	1.06	1.08	1.08	1.09	1.08	1.07	1.07	1.06	1.05
998	Miscellaneous Petroleum 2/	0.48	0.27	0.28	0.29	0.30	0.33	0.34	0.38	0.37	0.36	0.36	0.35	0.35	0.36
999	Petroleum Subtotal	6.74	5.88	6.05	6.29	6.52	6.78	6.87	6.93	6.89	6.86	6.84	6.82	6.83	6.82
1000	Natural Gas Heat and Power	4.99	4.43	4.68	5.05	5.39	5.78	5.97	6.02	5.98	5.99	6.00	6.00	6.00	6.01

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
962															
963	26.39	26.78	27.13	27.44	27.60	27.82	27.83	28.03	28.15	28.20	28.21	28.11	28.11	28.10	1.2%
964	28.59	29.12	29.46	29.69	30.22	30.25	30.83	30.80	30.18	30.26	30.37	30.78	30.97	31.08	2.4%
965	23.18	23.67	24.08	24.36	24.71	24.86	25.27	25.41	24.98	25.07	25.14	25.52	25.66	25.76	1.7%
966	17.29	17.70	18.01	18.25	18.38	18.52	18.60	18.59	18.66	18.53	18.57	18.87	18.96	19.00	1.8%
967	8.66	8.82	8.94	9.07	9.13	9.20	9.23	9.24	9.26	9.15	9.16	9.27	9.28	9.31	1.4%
968	5.64	5.76	5.91	6.01	6.12	6.20	6.29	6.31	6.35	6.47	6.64	6.93	7.20	7.44	2.0%
969	7.16	7.27	7.39	7.48	7.58	7.64	7.71	7.71	7.73	7.84	7.99	8.27	8.52	8.75	1.4%
970	6.37	6.44	6.43	6.52	6.52	6.55	6.56	6.58	6.58	6.62	6.63	6.62	6.61	6.57	0.7%
971	2.81	2.82	2.81	2.83	2.83	2.80	2.80	2.77	2.74	2.72	2.70	2.69	2.75	2.80	-0.3%
972	1.73	1.74	1.70	1.67	1.65	1.66	1.67	1.67	1.63	1.60	1.58	1.60	1.63	1.69	- -
973	18.24	18.53	18.73	18.96	19.30	19.60	20.04	20.45	20.78	21.05	21.58	22.33	23.16	24.08	0.8%
974															
975	33.07	34.17	35.24	36.24	37.10	38.07	38.79	39.80	40.72	41.56	42.41	43.09	43.98	44.85	3.0%
976	35.83	37.15	38.26	39.22	40.61	41.39	42.96	43.73	43.66	44.60	45.64	47.19	48.45	49.61	4.3%
977	29.05	30.20	31.28	32.18	33.21	34.01	35.22	36.08	36.14	36.94	37.78	39.12	40.14	41.12	3.6%
978	21.67	22.58	23.39	24.11	24.70	25.34	25.92	26.40	26.99	27.32	27.91	28.94	29.66	30.33	3.6%
979	10.85	11.25	11.61	11.98	12.27	12.59	12.86	13.13	13.39	13.48	13.76	14.21	14.53	14.86	3.2%
980	7.07	7.35	7.67	7.94	8.23	8.49	8.77	8.95	9.18	9.54	9.98	10.63	11.27	11.88	3.8%
981	8.97	9.27	9.60	9.88	10.18	10.45	10.74	10.94	11.18	11.56	12.01	12.67	13.34	13.96	3.3%
982	7.99	8.22	8.35	8.61	8.77	8.96	9.14	9.34	9.51	9.75	9.97	10.15	10.33	10.49	2.6%
983	3.52	3.60	3.65	3.74	3.80	3.83	3.90	3.94	3.97	4.00	4.06	4.13	4.30	4.46	1.5%
984	2.16	2.22	2.20	2.21	2.22	2.27	2.32	2.38	2.36	2.35	2.38	2.45	2.55	2.70	- -
985	22.86	23.64	24.32	25.05	25.94	26.82	27.93	29.05	30.07	31.02	32.44	34.23	36.23	38.44	2.6%
986															
987															
988															
989															
990	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.5%
991	2.02	2.02	2.01	2.00	1.98	1.96	1.94	1.93	1.92	1.90	1.89	1.87	1.85	1.82	0.1%
992	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.32	1.0%
993	1.16	1.16	1.15	1.15	1.15	1.15	1.14	1.13	1.13	1.13	1.12	1.12	1.12	1.12	-0.1%
994	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	-0.1%
995	1.28	1.28	1.28	1.28	1.27	1.26	1.26	1.25	1.25	1.24	1.24	1.23	1.22	1.21	1.2%
996	0.22	0.22	0.22	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.20	0.20	0.20	-1.3%
997	1.04	1.03	1.02	1.02	1.01	1.00	0.99	0.97	0.96	0.96	0.95	0.94	0.94	0.95	0.3%
998	0.36	0.35	0.35	0.35	0.34	0.34	0.33	0.33	0.32	0.32	0.31	0.31	0.30	0.30	0.4%
999	6.81	6.81	6.78	6.75	6.72	6.66	6.60	6.55	6.51	6.47	6.43	6.39	6.35	6.31	0.3%
1000	6.01	6.00	6.00	6.01	6.03	6.06	6.10	6.16	6.24	6.30	6.34	6.36	6.37	6.38	1.4%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1001	Natural Gas Feedstocks	0.59	0.55	0.60	0.61	0.60	0.62	0.63	0.60	0.58	0.57	0.56	0.56	0.57	0.56
1002	Lease and Plant Fuel 3/	1.26	1.19	1.31	1.29	1.25	1.23	1.21	1.28	1.25	1.25	1.26	1.27	1.28	1.28
1003	Natural Gas Subtotal	6.84	6.17	6.59	6.95	7.24	7.63	7.80	7.89	7.81	7.81	7.82	7.84	7.85	7.85
1004	Metallurgical Coal and Coke 4/	0.62	0.38	0.57	0.57	0.57	0.60	0.59	0.58	0.56	0.57	0.56	0.56	0.56	0.56
1005	Other Industrial Coal	1.10	0.88	0.90	0.90	0.91	0.93	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91
1006	Coal Subtotal	1.72	1.26	1.46	1.48	1.48	1.53	1.51	1.49	1.47	1.48	1.48	1.47	1.47	1.47
1007	Renewables 5/	1.52	1.42	1.49	1.62	1.74	1.88	1.81	1.87	1.87	1.91	1.93	1.94	1.97	1.99
1008	Purchased Electricity	3.27	2.82	3.01	3.13	3.24	3.40	3.38	3.38	3.35	3.35	3.36	3.36	3.37	3.36
1009	**Delivered Energy**	**20.09**	**17.56**	**18.60**	**19.46**	**20.22**	**21.22**	**21.38**	**21.55**	**21.39**	**21.42**	**21.42**	**21.44**	**21.48**	**21.50**
1010	Electricity Related Losses	7.06	6.04	6.43	6.64	6.85	7.10	7.04	6.80	6.76	6.76	6.73	6.71	6.70	6.66
1011	**Total**	**27.15**	**23.60**	**25.03**	**26.10**	**27.07**	**28.32**	**28.41**	**28.35**	**28.15**	**28.18**	**28.16**	**28.14**	**28.19**	**28.15**
1012															
1013															
1014	**Refining Consumption**														
1015	Liquefied Petroleum Gases Heat and Po	0.01	0.01	0.01	0.01	0.04	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04
1016	Distillate Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1017	Residual Fuel Oil	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1018	Petroleum Coke	0.51	0.52	0.52	0.52	0.59	0.60	0.59	0.59	0.59	0.58	0.57	0.56	0.55	0.55
1019	Still Gas	1.60	1.50	1.50	1.50	1.75	1.72	1.71	1.74	1.71	1.70	1.70	1.70	1.68	1.68
1020	Miscellaneous Petroleum 2/	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
1021	Petroleum Subtotal	2.16	2.05	2.05	2.05	2.40	2.38	2.37	2.40	2.36	2.34	2.33	2.32	2.29	2.30
1022	Natural Gas Heat and Power	1.25	1.34	1.45	1.47	1.39	1.43	1.43	1.37	1.39	1.42	1.43	1.45	1.47	1.45
1023	Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1024	Natural Gas Subtotal	1.25	1.34	1.45	1.47	1.39	1.43	1.43	1.37	1.39	1.42	1.43	1.45	1.47	1.45
1025	Other Industrial Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
1026	Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.11	0.11	0.11	0.12	0.13
1027	Coal Subtotal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.15	0.16	0.17	0.17	0.17	0.18	0.19
1028	Biofuels Heat and Coproducts	0.98	0.67	0.74	0.94	0.81	0.83	0.84	0.85	0.86	0.91	0.97	1.06	1.18	1.27
1029	Purchased Electricity	0.17	0.19	0.19	0.20	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.17
1030	**Delivered Energy**	**4.63**	**4.32**	**4.49**	**4.72**	**4.83**	**4.87**	**4.87**	**4.94**	**4.95**	**5.01**	**5.07**	**5.18**	**5.30**	**5.38**
1031	Electricity Related Losses	0.38	0.40	0.41	0.42	0.36	0.35	0.35	0.34	0.34	0.34	0.35	0.35	0.35	0.35
1032	**Total**	**5.00**	**4.72**	**4.91**	**5.15**	**5.18**	**5.22**	**5.22**	**5.28**	**5.29**	**5.35**	**5.41**	**5.53**	**5.66**	**5.73**
1033															
1034	**Total Industrial Sector Consumption**														
1035	Liquefied Petroleum Gases Heat and Po	0.24	0.22	0.21	0.24	0.29	0.29	0.30	0.30	0.29	0.29	0.29	0.29	0.29	0.29
1036	Liquefied Petroleum Gases Feedstocks	1.85	1.79	1.92	1.96	1.98	2.03	2.06	2.04	2.02	2.01	2.01	2.01	2.01	2.01
1037	Motor Gasoline	0.25	0.25	0.25	0.27	0.29	0.31	0.32	0.33	0.33	0.33	0.33	0.33	0.33	0.33
1038	Distillate Fuel Oil	1.27	1.16	1.19	1.19	1.22	1.24	1.20	1.15	1.16	1.16	1.16	1.16	1.16	1.16
1039	Residual Fuel Oil	0.20	0.17	0.18	0.18	0.17	0.17	0.17	0.18	0.17	0.17	0.17	0.17	0.17	0.17

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1001	0.56	0.55	0.55	0.53	0.53	0.51	0.51	0.49	0.49	0.48	0.47	0.46	0.45	0.44	-0.8%
1002	1.29	1.29	1.29	1.28	1.29	1.29	1.30	1.30	1.31	1.33	1.35	1.37	1.40	1.46	0.8%
1003	7.85	7.85	7.83	7.83	7.84	7.86	7.90	7.95	8.03	8.10	8.15	8.20	8.22	8.28	1.1%
1004	0.56	0.55	0.54	0.53	0.52	0.51	0.50	0.50	0.49	0.48	0.47	0.46	0.45	0.44	0.6%
1005	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.89	0.89	0.89	0.88	0.88	0.87	0.87	-0.1%
1006	1.47	1.46	1.45	1.44	1.42	1.41	1.40	1.39	1.38	1.37	1.35	1.34	1.33	1.31	0.1%
1007	2.01	2.02	2.02	2.04	2.04	2.04	2.03	2.04	2.04	2.03	2.02	2.02	2.02	2.01	1.3%
1008	3.35	3.34	3.31	3.29	3.25	3.21	3.15	3.10	3.05	3.00	2.95	2.90	2.86	2.82	0.0%
1009	**21.50**	**21.47**	**21.39**	**21.35**	**21.27**	**21.18**	**21.09**	**21.02**	**21.01**	**20.98**	**20.91**	**20.86**	**20.78**	**20.73**	**0.6%**
1010	6.59	6.52	6.44	6.38	6.29	6.19	6.07	5.98	5.88	5.73	5.60	5.47	5.35	5.22	-0.6%
1011	**28.08**	**27.98**	**27.83**	**27.73**	**27.56**	**27.37**	**27.16**	**27.00**	**26.89**	**26.71**	**26.50**	**26.33**	**26.13**	**25.95**	**0.4%**
1012															
1013															
1014															
1015	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	6.0%
1016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1018	0.55	0.54	0.55	0.55	0.55	0.55	0.56	0.56	0.57	0.57	0.57	0.58	0.58	0.58	0.5%
1019	1.70	1.68	1.69	1.69	1.68	1.69	1.68	1.70	1.72	1.75	1.76	1.77	1.80	1.81	0.7%
1020	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.5%
1021	2.31	2.29	2.31	2.30	2.30	2.31	2.30	2.33	2.36	2.39	2.41	2.42	2.45	2.47	0.7%
1022	1.40	1.41	1.41	1.41	1.41	1.41	1.44	1.42	1.43	1.42	1.42	1.43	1.42	1.41	0.2%
1023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1024	1.40	1.41	1.41	1.41	1.41	1.41	1.44	1.42	1.43	1.42	1.42	1.43	1.42	1.41	0.2%
1025	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
1026	0.16	0.26	0.31	0.37	0.42	0.49	0.56	0.63	0.71	0.79	0.87	0.96	1.05	1.13	- -
1027	0.22	0.32	0.37	0.42	0.48	0.55	0.62	0.69	0.77	0.85	0.93	1.02	1.10	1.19	12.2%
1028	1.37	1.54	1.73	1.88	1.99	2.09	2.23	2.26	2.30	2.34	2.36	2.46	2.50	2.51	5.2%
1029	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.1%
1030	**5.48**	**5.73**	**5.99**	**6.19**	**6.36**	**6.53**	**6.77**	**6.89**	**7.04**	**7.19**	**7.31**	**7.52**	**7.66**	**7.77**	**2.3%**
1031	0.34	0.34	0.34	0.34	0.34	0.34	0.35	0.35	0.36	0.36	0.35	0.35	0.35	0.35	-0.5%
1032	**5.82**	**6.07**	**6.33**	**6.53**	**6.70**	**6.87**	**7.12**	**7.25**	**7.39**	**7.54**	**7.66**	**7.87**	**8.01**	**8.12**	**2.1%**
1033															
1034															
1035	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.28	1.0%
1036	2.02	2.02	2.01	2.00	1.98	1.96	1.94	1.93	1.92	1.90	1.89	1.87	1.85	1.82	0.1%
1037	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.32	1.0%
1038	1.16	1.16	1.15	1.15	1.15	1.15	1.14	1.13	1.13	1.13	1.12	1.12	1.12	1.12	-0.1%
1039	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	-0.3%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1040	Petrochemical Feedstocks	1.12	0.90	0.97	1.06	1.10	1.18	1.24	1.27	1.26	1.26	1.26	1.26	1.27	1.27
1041	Petroleum Coke	0.87	0.80	0.74	0.74	0.80	0.82	0.81	0.82	0.82	0.81	0.79	0.78	0.77	0.78
1042	Asphalt and Road Oil	1.01	0.87	0.85	0.90	1.00	1.06	1.08	1.08	1.09	1.08	1.07	1.07	1.06	1.05
1043	Still Gas	1.60	1.50	1.50	1.50	1.75	1.72	1.71	1.74	1.71	1.70	1.70	1.70	1.68	1.68
1044	Miscellaneous Petroleum 2/	0.50	0.28	0.29	0.31	0.33	0.35	0.36	0.40	0.39	0.39	0.38	0.38	0.38	0.38
1045	Petroleum Subtotal	8.91	7.94	8.11	8.34	8.92	9.16	9.24	9.33	9.25	9.20	9.17	9.14	9.12	9.12
1046	Natural Gas Heat and Power	6.24	5.77	6.13	6.51	6.78	7.21	7.40	7.39	7.37	7.41	7.43	7.46	7.47	7.45
1047	Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1048	Natural Gas Feedstocks	0.59	0.55	0.60	0.61	0.60	0.62	0.63	0.60	0.58	0.57	0.56	0.56	0.57	0.56
1049	Lease and Plant Fuel 3/	1.26	1.19	1.31	1.29	1.25	1.23	1.21	1.28	1.25	1.25	1.26	1.27	1.28	1.28
1050	Natural Gas Subtotal	8.09	7.51	8.04	8.42	8.63	9.06	9.23	9.26	9.20	9.23	9.25	9.29	9.32	9.30
1051	Metallurgical Coal and Coke 4/	0.62	0.38	0.57	0.57	0.57	0.60	0.59	0.58	0.56	0.57	0.56	0.56	0.56	0.56
1052	Other Industrial Coal	1.16	0.94	0.96	0.96	0.97	0.99	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
1053	Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.11	0.11	0.11	0.12	0.13
1054	Coal Subtotal	1.78	1.32	1.52	1.54	1.54	1.59	1.57	1.65	1.64	1.64	1.64	1.64	1.65	1.66
1055	Biofuels Heat and Coproducts	0.98	0.67	0.74	0.94	0.81	0.83	0.84	0.85	0.86	0.91	0.97	1.06	1.18	1.27
1056	Renewables 5/	1.52	1.42	1.49	1.62	1.74	1.88	1.81	1.87	1.87	1.91	1.93	1.94	1.97	1.99
1057	Purchased Electricity	3.44	3.01	3.20	3.32	3.41	3.56	3.55	3.54	3.52	3.52	3.53	3.53	3.54	3.54
1058	**Delivered Energy**	**24.72**	**21.87**	**23.10**	**24.18**	**25.05**	**26.09**	**26.25**	**26.49**	**26.33**	**26.42**	**26.49**	**26.62**	**26.79**	**26.88**
1059	Electricity Related Losses	7.44	6.44	6.84	7.07	7.20	7.45	7.39	7.14	7.10	7.11	7.08	7.06	7.06	7.00
1060	**Total**	**32.16**	**28.32**	**29.94**	**31.25**	**32.25**	**33.54**	**33.64**	**33.63**	**33.43**	**33.53**	**33.57**	**33.67**	**33.84**	**33.88**
1061															
1062	**Energy Consumption per dollar of Shipment 1/**														
1063	**(thousand Btu per 2005 dollar)**														
1064	Liquefied Petroleum Gases Heat and Po	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
1065	Liquefied Petroleum Gases Feedstocks	0.27	0.30	0.31	0.30	0.29	0.28	0.28	0.27	0.27	0.27	0.26	0.26	0.25	0.25
1066	Motor Gasoline	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
1067	Distillate Fuel Oil	0.19	0.19	0.19	0.18	0.18	0.17	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.14
1068	Residual Fuel Oil	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
1069	Petrochemical Feedstocks	0.17	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16
1070	Petroleum Coke	0.13	0.13	0.12	0.11	0.12	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10
1071	Asphalt and Road Oil	0.15	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13
1072	Still Gas	0.24	0.25	0.24	0.23	0.25	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.21	0.21
1073	Miscellaneous Petroleum 2/	0.07	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
1074	Petroleum Subtotal	1.33	1.32	1.30	1.27	1.29	1.26	1.25	1.25	1.24	1.21	1.19	1.17	1.16	1.14
1075	Natural Gas Heat and Power	0.93	0.96	0.98	0.99	0.98	0.99	1.00	0.99	0.98	0.98	0.97	0.96	0.95	0.93
1076	Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1077	Natural Gas Feedstock	0.09	0.09	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07
1078	Lease and Plant Fuel 3/	0.19	0.20	0.21	0.20	0.18	0.17	0.16	0.17	0.17	0.17	0.16	0.16	0.16	0.16

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1040	1.28	1.28	1.28	1.28	1.27	1.26	1.26	1.25	1.25	1.24	1.24	1.23	1.22	1.21	1.2%
1041	0.77	0.76	0.76	0.76	0.76	0.77	0.77	0.77	0.77	0.77	0.78	0.78	0.79	0.79	-0.1%
1042	1.04	1.03	1.02	1.02	1.01	1.00	0.99	0.97	0.96	0.96	0.95	0.94	0.94	0.95	0.3%
1043	1.70	1.68	1.69	1.69	1.68	1.69	1.68	1.70	1.72	1.75	1.76	1.77	1.80	1.81	0.7%
1044	0.38	0.38	0.37	0.37	0.37	0.36	0.36	0.35	0.34	0.34	0.34	0.33	0.33	0.32	0.5%
1045	9.12	9.10	9.08	9.06	9.01	8.97	8.91	8.88	8.87	8.87	8.83	8.81	8.80	8.78	0.4%
1046	7.40	7.41	7.40	7.42	7.44	7.46	7.53	7.58	7.66	7.72	7.76	7.79	7.79	7.79	1.2%
1047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1048	0.56	0.55	0.55	0.53	0.53	0.51	0.51	0.49	0.49	0.48	0.47	0.46	0.45	0.44	-0.8%
1049	1.29	1.29	1.29	1.28	1.29	1.29	1.30	1.30	1.31	1.33	1.35	1.37	1.40	1.46	0.8%
1050	9.25	9.25	9.24	9.24	9.25	9.27	9.34	9.37	9.46	9.52	9.57	9.63	9.64	9.69	1.0%
1051	0.56	0.55	0.54	0.53	0.52	0.51	0.50	0.50	0.49	0.48	0.47	0.46	0.45	0.44	0.6%
1052	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.94	0.94	0.93	0.93	-0.1%
1053	0.16	0.26	0.31	0.37	0.42	0.49	0.56	0.63	0.71	0.79	0.87	0.96	1.05	1.13	- -
1054	1.69	1.78	1.82	1.86	1.91	1.96	2.02	2.08	2.15	2.22	2.29	2.36	2.43	2.50	2.5%
1055	1.37	1.54	1.73	1.88	1.99	2.09	2.23	2.26	2.30	2.34	2.36	2.46	2.50	2.51	5.2%
1056	2.01	2.02	2.02	2.04	2.04	2.04	2.03	2.04	2.04	2.03	2.02	2.02	2.02	2.01	1.3%
1057	3.53	3.51	3.49	3.47	3.43	3.38	3.33	3.28	3.24	3.19	3.14	3.09	3.05	3.01	0.0%
1058	**26.97**	**27.20**	**27.38**	**27.54**	**27.63**	**27.71**	**27.86**	**27.91**	**28.05**	**28.17**	**28.21**	**28.37**	**28.44**	**28.50**	**1.0%**
1059	6.93	6.86	6.78	6.72	6.63	6.53	6.42	6.33	6.23	6.09	5.95	5.82	5.71	5.57	-0.6%
1060	**33.90**	**34.05**	**34.16**	**34.26**	**34.26**	**34.24**	**34.28**	**34.24**	**34.28**	**34.25**	**34.16**	**34.20**	**34.15**	**34.07**	**0.7%**
1061															
1062															
1063															
1064	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.7%
1065	0.25	0.25	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.21	0.21	0.21	0.20	0.20	-1.6%
1066	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	-0.7%
1067	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	-1.8%
1068	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-2.0%
1069	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.13	0.13	-0.5%
1070	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	-1.7%
1071	0.13	0.13	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	-1.3%
1072	0.21	0.21	0.21	0.20	0.20	0.20	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.20	-0.9%
1073	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	-1.2%
1074	1.13	1.11	1.10	1.08	1.07	1.05	1.03	1.02	1.01	1.00	0.98	0.97	0.96	0.95	-1.3%
1075	0.92	0.91	0.90	0.89	0.88	0.87	0.87	0.87	0.87	0.87	0.86	0.86	0.85	0.84	-0.5%
1076	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1077	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	-2.4%
1078	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	-0.9%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1079	Natural Gas Subtotal	1.20	1.25	1.29	1.28	1.25	1.24	1.25	1.24	1.23	1.22	1.21	1.19	1.18	1.17
1080	Metallurgical Coal and Coke 4/	0.09	0.06	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07
1081	Other Industrial Coal	0.17	0.16	0.15	0.15	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12
1082	Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02
1083	Coal Subtotal	0.27	0.22	0.24	0.23	0.22	0.22	0.21	0.22	0.22	0.22	0.21	0.21	0.21	0.21
1084	Biofuels Heat and Coproducts	0.15	0.11	0.12	0.14	0.12	0.11	0.11	0.11	0.12	0.12	0.13	0.14	0.15	0.16
1085	Renewables 5/	0.23	0.24	0.24	0.25	0.25	0.26	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
1086	Purchased Electricity	0.51	0.50	0.51	0.51	0.49	0.49	0.48	0.48	0.47	0.47	0.46	0.45	0.45	0.44
1087	**Delivered Energy**	**3.68**	**3.64**	**3.70**	**3.68**	**3.63**	**3.58**	**3.56**	**3.56**	**3.52**	**3.49**	**3.45**	**3.42**	**3.39**	**3.37**
1088	Electricity Related Losses	1.11	1.07	1.10	1.08	1.04	1.02	1.00	0.96	0.95	0.94	0.92	0.91	0.89	0.88
1089	**Total**	**4.79**	**4.71**	**4.79**	**4.76**	**4.68**	**4.60**	**4.56**	**4.52**	**4.46**	**4.43**	**4.38**	**4.33**	**4.29**	**4.24**
1090															
1091	**Total Industrial Combined Heat and Power**														
1092	Capacity (gigawatts)	25.73	27.98	30.10	31.82	33.60	34.68	35.18	36.77	37.38	38.01	38.61	39.34	40.44	41.83
1093	Generation (billion kilowatthours)	135.57	152.58	167.53	179.66	190.70	198.34	202.08	213.30	217.72	221.83	226.50	232.53	240.95	251.90
1094															
1095															
1096															
1097															
1098	1/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity,														
1099	or electricity and heat, to the public.														
1100	2/ Includes lubricants and miscellaneous petroleum products.														
1101	3/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.														
1102	4/ Includes net coal coke imports.														
1103	5/ Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.														
1104	Btu = British thermal unit.														
1105	- - = Not applicable.														
1106	Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009														
1107	are model results and may differ slightly from official EIA data reports.														
1108	Sources: 2008 and 2009 prices for motor gasoline and distillate fuel oil														
1109	are based on: U.S. Energy Information Administration (EIA), Petroleum Marketing Annual														
1110	2009, DOE/EIA-0487(2009) (Washington, DC, August 2010).														
1111	2008 and 2009 petrochemical feedstock and asphalt and road oil prices are based on: EIA,														
1112	State Energy Data Report 2008, DOE/EIA-0214(2008) (Washington, DC, June 2010).														
1113	2008 and 2009 coal prices are based on: EIA, Quarterly Coal Report,														
1114	October-December 2009, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
1115	2008 and 2009 electricity prices: Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).														
1116	2008 and 2009 natural gas prices are based on: EIA,														
1117	Manufacturing Energy Consumption Survey and industrial and wellhead prices from the Natural Gas Annual														
1118	2008, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the Natural Gas Monthly, DOE/EIA-0130(2010/07) (Washington, DC, July 2010).														
1119	2008 refining consumption values are based on: Petroleum Supply Annual														
1120	2008, DOE/EIA-0340(2008)/1 (Washington, DC, June 2009).														
1121	2009 refining consumption based on: Petroleum Supply Annual														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1079	1.15	1.13	1.12	1.10	1.09	1.08	1.08	1.08	1.08	1.07	1.07	1.06	1.05	1.05	-0.7%
1080	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	-1.1%
1081	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	-1.7%
1082	0.02	0.03	0.04	0.04	0.05	0.06	0.06	0.07	0.08	0.09	0.10	0.11	0.11	0.12	- -
1083	0.21	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.27	0.27	0.8%
1084	0.17	0.19	0.21	0.23	0.24	0.24	0.26	0.26	0.26	0.26	0.26	0.27	0.27	0.27	3.5%
1085	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.22	0.22	0.22	-0.3%
1086	0.44	0.43	0.42	0.41	0.41	0.40	0.39	0.38	0.37	0.36	0.35	0.34	0.33	0.32	-1.6%
1087	**3.34**	**3.33**	**3.32**	**3.29**	**3.27**	**3.24**	**3.24**	**3.21**	**3.19**	**3.17**	**3.14**	**3.13**	**3.10**	**3.08**	**-0.6%**
1088	0.86	0.84	0.82	0.80	0.78	0.76	0.75	0.73	0.71	0.68	0.66	0.64	0.62	0.60	-2.2%
1089	**4.20**	**4.17**	**4.14**	**4.10**	**4.05**	**4.01**	**3.98**	**3.94**	**3.90**	**3.85**	**3.80**	**3.77**	**3.72**	**3.68**	**-0.9%**
1090															
1091															
1092	43.64	46.20	48.50	51.05	53.61	56.52	59.25	61.86	64.65	67.39	69.91	72.19	74.22	76.02	3.9%
1093	266.04	285.98	304.06	323.54	342.74	364.45	384.60	404.12	425.03	445.88	464.76	482.27	497.53	511.08	4.8%
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1122	2009, DOE/EIA-0340(2009)/1 (Washington, DC, July 2010).														
1123	Other 2008 and 2009 consumption values are based on: EIA, Annual Energy Review														
1124	2009, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 shipments: IHS Global Insight,														
1125	Global Insight Industry model, September 2010.														
1126	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
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1150	**7. Transportation Sector Key Indicators and Delivered Energy Consumption**														
1151															
1152															
1153	*Key Indicators and Consumption*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1154															
1155	**Key Indicators**														
1156	**Travel Indicators**														
1157	**(billion vehicle miles traveled)**														
1158	Light-Duty Vehicles < 8500 pounds	2690	2707	2734	2755	2804	2854	2899	2946	2996	3043	3090	3139	3190	3247
1159	Commercial Light Trucks 1/	72	67	69	72	75	78	79	80	81	82	83	85	86	87
1160	Freight Trucks > 10000 pounds	228	207	215	227	235	246	248	249	250	254	258	262	266	270
1161	**(billion seat miles available)**														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1122															
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1151															
1152															**2009-**
1153	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
1154															
1155															
1156															
1157															
1158	3300	3352	3404	3460	3509	3572	3620	3681	3751	3813	3871	3925	3980	4036	1.5%
1159	88	89	91	92	93	94	95	96	98	99	100	101	102	104	1.7%
1160	275	279	283	288	292	296	300	304	309	314	318	322	326	331	1.8%
1161															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1162	Air	1014	960	994	1003	1014	1028	1044	1058	1072	1085	1097	1109	1121	1133
1163	**(billion ton miles traveled)**														
1164	Rail	1777	1677	1740	1771	1844	1892	1874	1742	1786	1800	1822	1826	1850	1841
1165	Domestic Shipping	521	486	498	490	494	508	514	528	530	535	541	547	553	557
1166															
1167	**Energy Efficiency Indicators**														
1168	**(miles per gallon)**														
1169	New Light-Duty Vehicle CAFE Standard :	25.2	25.4	25.6	27.3	29.5	30.4	31.3	32.6	34.1	34.4	34.7	35.0	35.4	35.4
1170	New Car	28.4	28.4	28.4	31.7	34.9	35.7	36.5	37.8	39.5	39.7	39.9	40.2	40.4	40.4
1171	New Light Truck	22.4	23.0	23.4	23.9	25.5	26.2	26.9	28.0	29.2	29.3	29.5	29.6	29.7	29.7
1172	Compliance New Light-Duty Vehicle 3/	28.0	29.1	29.1	29.8	30.5	30.9	31.5	32.5	33.3	34.3	35.1	35.3	35.8	36.1
1173	New Car	32.5	33.7	34.0	35.0	35.8	36.1	36.7	37.8	38.6	39.6	40.1	40.3	40.7	40.9
1174	New Light Truck	24.2	25.5	25.5	25.9	26.4	26.7	27.1	27.8	28.4	29.2	29.9	30.0	30.3	30.5
1175	Tested New Light-Duty Vehicle 4/	28.0	28.0	27.9	28.5	29.2	29.6	30.2	31.2	32.1	33.1	33.8	34.1	34.5	34.8
1176	New Car	32.5	32.7	32.9	33.8	34.6	34.9	35.4	36.5	37.3	38.4	38.9	39.1	39.5	39.7
1177	New Light Truck	24.2	24.3	24.3	24.7	25.2	25.5	25.9	26.6	27.2	28.0	28.7	28.8	29.1	29.3
1178	On-Road New Light-Duty Vehicle 5/	23.2	23.2	23.2	23.7	24.3	24.6	25.1	26.0	26.7	27.5	28.2	28.4	28.8	29.0
1179	New Car	26.5	26.7	26.9	27.6	28.4	28.6	29.1	30.1	30.7	31.6	32.1	32.3	32.6	32.9
1180	New Light Truck	20.3	20.4	20.4	20.7	21.2	21.4	21.7	22.3	22.9	23.5	24.1	24.2	24.4	24.6
1181	Light-Duty Stock 6/	20.8	20.8	20.8	21.0	21.2	21.5	21.7	22.1	22.4	22.8	23.1	23.5	23.9	24.3
1182	New Commercial Light Truck 1/	15.4	15.6	15.7	15.7	15.8	15.9	16.1	16.4	16.7	17.1	17.5	17.6	17.7	17.9
1183	Stock Commercial Light Truck 1/	14.3	14.4	14.5	14.6	14.8	14.9	15.0	15.2	15.4	15.6	15.8	16.1	16.3	16.5
1184	Freight Truck	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2
1185	**(seat miles per gallon)**														
1186	Aircraft	61.8	62.0	62.1	62.1	62.3	62.4	62.6	62.8	63.1	63.3	63.5	63.8	64.1	64.4
1187	**(ton miles/thousand Btu)**														
1188	Rail	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
1189	Domestic Shipping	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5
1190															
1191	**Energy Use by Mode**														
1192	**(quadrillion Btu)**														
1193	Light-Duty Vehicles	16.14	16.13	16.17	16.14	16.24	16.31	16.35	16.36	16.36	16.34	16.29	16.26	16.24	16.25
1194	Commercial Light Trucks 1/	0.63	0.58	0.59	0.61	0.64	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
1195	Bus Transportation	0.27	0.27	0.27	0.27	0.27	0.28	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.30
1196	Freight Trucks	4.70	4.26	4.40	4.63	4.79	5.04	5.06	5.09	5.11	5.17	5.24	5.30	5.37	5.43
1197	Rail, Passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06
1198	Rail, Freight	0.58	0.51	0.53	0.54	0.56	0.57	0.57	0.53	0.54	0.54	0.55	0.55	0.56	0.55
1199	Shipping, Domestic	0.23	0.20	0.21	0.20	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.23	0.23	0.23
1200	Shipping, International	0.90	0.78	0.79	0.79	0.78	0.78	0.78	0.78	0.79	0.79	0.79	0.79	0.79	0.79

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1162	1146	1157	1168	1180	1191	1202	1213	1223	1234	1244	1253	1263	1272	1282	1.1%
1163															
1164	1857	1838	1849	1850	1851	1843	1835	1817	1802	1791	1773	1780	1822	1824	0.3%
1165	563	567	569	571	574	580	584	589	594	601	609	615	623	625	1.0%
1166															
1167															
1168															
1169	35.5	35.5	35.6	35.6	35.7	35.7	35.8	35.8	35.8	35.8	35.8	35.9	35.9	35.9	1.3%
1170	40.4	40.5	40.4	40.4	40.5	40.4	40.5	40.4	40.4	40.4	40.4	40.4	40.4	40.4	1.4%
1171	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.8	29.7	29.7	29.7	29.7	29.7	1.0%
1172	36.2	36.3	36.4	36.6	36.8	36.8	37.1	37.1	37.2	37.3	37.4	37.6	37.7	37.8	1.0%
1173	41.0	41.1	41.1	41.2	41.4	41.4	41.6	41.6	41.6	41.7	41.8	41.9	41.9	42.0	0.8%
1174	30.6	30.6	30.7	30.8	30.9	31.0	31.1	31.2	31.3	31.4	31.5	31.6	31.7	31.8	0.9%
1175	34.9	35.1	35.2	35.3	35.5	35.6	35.8	35.9	35.9	36.1	36.2	36.3	36.4	36.5	1.0%
1176	39.8	39.8	39.8	40.0	40.1	40.2	40.3	40.3	40.4	40.5	40.5	40.6	40.7	40.8	0.9%
1177	29.4	29.4	29.5	29.6	29.7	29.8	29.9	30.0	30.1	30.2	30.3	30.4	30.5	30.6	0.9%
1178	29.2	29.3	29.4	29.5	29.7	29.8	30.0	30.1	30.1	30.2	30.3	30.4	30.5	30.6	1.1%
1179	33.0	33.1	33.1	33.3	33.4	33.5	33.7	33.7	33.8	33.9	33.9	34.0	34.1	34.1	1.0%
1180	24.7	24.7	24.8	24.8	24.9	25.0	25.1	25.2	25.3	25.4	25.5	25.5	25.6	25.7	0.9%
1181	24.6	25.0	25.3	25.7	26.0	26.2	26.5	26.8	27.0	27.2	27.4	27.6	27.7	27.9	1.1%
1182	17.9	17.9	17.9	17.9	17.9	17.9	17.9	18.0	18.0	18.0	18.1	18.1	18.1	18.1	0.6%
1183	16.7	16.9	17.1	17.2	17.4	17.5	17.6	17.7	17.7	17.8	17.9	17.9	17.9	18.0	0.9%
1184	6.3	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.5	6.5	6.5	6.6	6.6	6.6	0.3%
1185															
1186	64.7	65.0	65.3	65.6	66.0	66.3	66.7	67.1	67.5	68.0	68.4	68.9	69.4	69.9	0.5%
1187															
1188	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.4	0.1%
1189	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.2%
1190															
1191															
1192															
1193	16.26	16.27	16.30	16.36	16.39	16.51	16.56	16.69	16.86	17.02	17.17	17.31	17.46	17.62	0.3%
1194	0.66	0.66	0.66	0.67	0.67	0.67	0.68	0.68	0.69	0.70	0.70	0.71	0.71	0.72	0.8%
1195	0.30	0.30	0.30	0.30	0.31	0.31	0.31	0.31	0.32	0.32	0.32	0.32	0.33	0.33	0.8%
1196	5.49	5.54	5.60	5.67	5.72	5.78	5.82	5.88	5.95	6.02	6.08	6.14	6.20	6.26	1.5%
1197	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07	1.1%
1198	0.56	0.55	0.56	0.56	0.55	0.55	0.55	0.54	0.54	0.53	0.53	0.53	0.54	0.54	0.2%
1199	0.23	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.25	0.25	0.25	0.8%
1200	0.79	0.79	0.79	0.79	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.1%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1201	Recreational Boats	0.25	0.26	0.26	0.27	0.27	0.27	0.27	0.27	0.28	0.28	0.28	0.28	0.28	0.28
1202	Air	2.70	2.66	2.58	2.60	2.61	2.64	2.68	2.71	2.73	2.76	2.79	2.82	2.84	2.87
1203	Military Use	0.71	0.75	0.76	0.75	0.73	0.70	0.69	0.69	0.68	0.69	0.69	0.69	0.70	0.70
1204	Lubricants	0.14	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13
1205	Pipeline Fuel	0.67	0.65	0.67	0.65	0.64	0.64	0.65	0.70	0.68	0.67	0.68	0.68	0.69	0.68
1206	**Total**	**27.95**	**27.23**	**27.42**	**27.62**	**27.91**	**28.29**	**28.38**	**28.45**	**28.51**	**28.59**	**28.66**	**28.74**	**28.83**	**28.93**
1207															
1208	**(million barrels per day oil equivalent)**														
1209	Light-Duty Vehicles	8.55	8.62	8.68	8.70	8.75	8.80	8.82	8.83	8.83	8.85	8.85	8.86	8.87	8.85
1210	Commercial Light Trucks 1/	0.32	0.30	0.30	0.31	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
1211	Bus Transportation	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14
1212	Freight Trucks	2.26	2.05	2.12	2.23	2.31	2.43	2.44	2.45	2.46	2.49	2.52	2.55	2.58	2.61
1213	Rail, Passenger	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
1214	Rail, Freight	0.27	0.24	0.25	0.26	0.27	0.27	0.27	0.25	0.26	0.26	0.26	0.26	0.27	0.26
1215	Shipping, Domestic	0.11	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11
1216	Shipping, International	0.39	0.34	0.35	0.35	0.34	0.34	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35
1217	Recreational Boats	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
1218	Air	1.31	1.29	1.25	1.26	1.26	1.28	1.30	1.31	1.32	1.34	1.35	1.36	1.37	1.39
1219	Military Use	0.34	0.36	0.37	0.36	0.35	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.34
1220	Lubricants	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
1221	Pipeline Fuel	0.31	0.31	0.31	0.31	0.30	0.30	0.31	0.33	0.32	0.32	0.32	0.32	0.32	0.32
1222	**Total**	**14.22**	**13.95**	**14.08**	**14.22**	**14.37**	**14.56**	**14.61**	**14.64**	**14.68**	**14.74**	**14.80**	**14.86**	**14.93**	**14.95**
1223															
1224															
1225															
1226	1/ Commercial trucks 8,500 to 10,000 pounds gross vehicle weight rating.														
1227	2/ CAFE standard based on projected new vehicle sales.														
1228	3/ Includes CAFE credits for alternative fueled vehicles sales and credit banking.														
1229	4/ Environmental Protection Agency rated miles per gallon.														
1230	5/ Tested new vehicle efficiency revised for on-road performance.														
1231	6/ Combined car and light truck "on-the-road" estimate.														
1232	Btu = British thermal unit.														
1233	Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009														
1234	are model results and may differ slightly from official EIA data reports.														
1235	Sources: 2008 and 2009: U.S. Energy Information Administration (EIA), Natural Gas Annual														
1236	2008, DOE/EIA-0131(2008) (Washington, DC, March 2010); EIA, Annual Energy Review														
1237	2009, DOE/EIA-0384(2009) (Washington, DC, August 2010);														
1238	Federal Highway Administration, Highway Statistics 2008 (Washington, DC, April 2010);														
1239	Oak Ridge National Laboratory, Transportation Energy Data Book: Edition 29 and Annual (Oak Ridge, TN, 2010);														
1240	National Highway Traffic and Safety Administration, Summary of Fuel Economy Performance (Washington, DC, December 9, 2009);														
1241	U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004);														
1242	EIA, Alternatives to Traditional Transportation Fuels 2008 (Part II - User and Fuel Data), April 2010;														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1201	0.29	0.29	0.29	0.29	0.29	0.29	0.30	0.30	0.30	0.30	0.30	0.30	0.31	0.31	0.6%
1202	2.89	2.91	2.93	2.95	2.97	2.99	3.00	3.02	3.03	3.04	3.05	3.06	3.07	3.07	0.6%
1203	0.71	0.71	0.71	0.72	0.72	0.73	0.73	0.73	0.74	0.74	0.74	0.75	0.75	0.76	0.0%
1204	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.1%
1205	0.69	0.69	0.69	0.68	0.68	0.69	0.69	0.69	0.69	0.70	0.71	0.72	0.73	0.78	0.7%
1206	**29.04**	**29.13**	**29.25**	**29.41**	**29.53**	**29.74**	**29.86**	**30.07**	**30.35**	**30.62**	**30.85**	**31.09**	**31.35**	**31.65**	**0.6%**
1207															
1208															
1209	8.90	8.95	9.02	9.07	9.12	9.17	9.26	9.30	9.38	9.47	9.56	9.63	9.71	9.79	0.5%
1210	0.34	0.34	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.36	0.36	0.36	0.37	0.37	0.8%
1211	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.8%
1212	2.64	2.67	2.69	2.72	2.75	2.78	2.80	2.83	2.86	2.89	2.92	2.95	2.98	3.01	1.5%
1213	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	1.1%
1214	0.27	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.25	0.25	0.25	0.26	0.26	0.2%
1215	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.8%
1216	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.1%
1217	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.7%
1218	1.40	1.41	1.42	1.43	1.44	1.44	1.45	1.46	1.47	1.47	1.48	1.48	1.48	1.49	0.6%
1219	0.34	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.1%
1220	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
1221	0.32	0.32	0.32	0.32	0.32	0.32	0.33	0.33	0.33	0.33	0.34	0.34	0.34	0.37	0.7%
1222	**15.05**	**15.14**	**15.25**	**15.35**	**15.44**	**15.53**	**15.66**	**15.74**	**15.87**	**16.01**	**16.14**	**16.25**	**16.39**	**16.54**	**0.7%**
1223															
1224															
1225															
1226															
1227															
1228															
1229															
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1231															
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1243	EIA, State Energy Data Report 2008, DOE/EIA-0214(2008) (Washington, DC, June 2010);														
1244	U.S. Department of Transportation, Research and Special Programs Administration, Air Carrier Statistics Monthly,														
1245	December 2009/2008 (Washington, DC, December 2009); EIA, Fuel Oil and Kerosene Sales 2008, DOE/EIA-0535(2008) (Washington, DC, December 2009);														
1246	and United States Department of Defense, Defense Fuel Supply Center, Factbook (January 2010).														
1247	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
1275	**8. Electricity Supply, Disposition, Prices, and Emissions**														
1276	**(billion kilowatthours, unless otherwise noted)**														
1278	*Supply, Disposition, and Prices*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1280	**Net Generation by Fuel Type**														
1282	**Electric Power Sector 1/**														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1243															
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1274															
1275															
1276															
1277															**2009-**
1278	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
1279															
1280															
1281															
1282															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1283	**Power Only 2/**														
1284	Coal	1932	1719	1829	1791	1828	1829	1801	1484	1533	1493	1460	1440	1468	1450
1285	Petroleum	39	32	40	39	39	39	38	39	38	39	39	38	38	38
1286	Natural Gas 3/	683	722	762	713	640	643	652	891	849	862	897	926	957	969
1287	Nuclear Power	806	799	803	803	813	827	833	839	809	803	813	824	824	818
1288	Pumped Storage/Other 4/	0	2	0	0	0	0	0	0	0	0	0	0	0	0
1289	Renewable Sources 5/	347	380	371	407	490	514	535	578	620	682	701	712	694	728
1290	Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1291	**Total**	**3807**	**3653**	**3804**	**3752**	**3810**	**3852**	**3858**	**3831**	**3849**	**3879**	**3911**	**3939**	**3980**	**4004**
1292	**Combined Heat and Power 6/**														
1293	Coal	37	30	28	26	24	23	22	15	16	15	14	14	14	14
1294	Petroleum	4	4	0	0	0	0	0	0	0	0	0	0	0	0
1295	Natural Gas	119	119	128	126	116	116	117	156	146	146	150	156	146	141
1296	Renewable Sources	4	4	3	3	3	3	3	4	5	6	6	6	6	6
1297	**Total**	**167**	**161**	**159**	**155**	**143**	**142**	**142**	**175**	**168**	**167**	**170**	**176**	**166**	**161**
1298	**Total Net Generation**	**3974**	**3814**	**3963**	**3908**	**3953**	**3994**	**4000**	**4006**	**4017**	**4047**	**4081**	**4115**	**4146**	**4165**
1299	Less Direct Use	35	35	33	33	33	33	33	33	33	33	33	33	33	33
1300															
1301	**Net Available to the Grid**	**3939**	**3779**	**3930**	**3874**	**3919**	**3960**	**3967**	**3973**	**3984**	**4014**	**4049**	**4083**	**4113**	**4133**
1302															
1303	**End-Use Generation 7/**														
1304	Coal	19	23	23	23	23	23	23	29	30	30	31	31	31	32
1305	Petroleum	3	5	5	5	5	5	5	5	5	5	5	5	5	5
1306	Natural Gas	80	90	102	112	117	122	125	128	131	132	134	136	138	141
1307	Other Gaseous Fuels 8/	11	11	11	11	14	15	15	15	15	14	14	15	15	15
1308	Renewable Sources 9/	34	36	41	46	51	55	57	62	65	68	72	76	82	89
1309	Other 10/	2	2	1	1	1	1	1	1	1	1	1	1	1	1
1310	**Total**	**149**	**167**	**183**	**198**	**211**	**220**	**226**	**240**	**247**	**251**	**256**	**263**	**272**	**284**
1311	Less Direct Use	120	135	149	161	171	179	183	194	199	202	205	208	212	217
1312	**Total Sales to the Grid**	**29**	**31**	**35**	**37**	**40**	**42**	**43**	**46**	**47**	**49**	**52**	**55**	**60**	**66**
1313															
1314	**Total Electricity Generation by Fuel**														
1315	Coal	1987	1772	1880	1840	1875	1875	1846	1528	1580	1538	1505	1484	1513	1497
1316	Petroleum	46	41	45	44	44	44	43	44	44	44	44	44	43	44
1317	Natural Gas	882	931	993	951	873	881	894	1174	1126	1141	1181	1218	1241	1251
1318	Nuclear Power	806	799	803	803	813	827	833	839	809	803	813	824	824	818
1319	Renewable Sources 5,9/	385	420	414	455	543	572	595	644	690	756	778	793	781	823
1320	Other 11/	16	18	12	12	16	16	16	16	16	15	15	16	16	16
1321	**Total Electricity Generation**	**4123**	**3980**	**4147**	**4105**	**4163**	**4214**	**4226**	**4246**	**4264**	**4298**	**4337**	**4378**	**4418**	**4449**

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1283															
1284	1450	1417	1397	1369	1333	1286	1229	1179	1106	1022	948	919	973	932	-2.3%
1285	39	38	38	38	38	37	37	37	37	37	37	37	38	38	0.7%
1286	1003	1026	1045	1058	1074	1090	1109	1110	1153	1225	1290	1374	1439	1563	3.0%
1287	809	821	838	859	882	908	938	972	1011	1039	1076	1023	885	783	-0.1%
1288	0	0	0	0	0	0	0	0	0	0	0	0	0	0	- -
1289	730	754	771	790	808	828	850	874	893	891	878	881	895	892	3.3%
1290	0	0	0	0	0	0	0	0	0	0	0	0	0	0	- -
1291	**4032**	**4057**	**4089**	**4113**	**4133**	**4149**	**4164**	**4173**	**4201**	**4214**	**4230**	**4234**	**4230**	**4208**	**0.5%**
1292															
1293	14	13	13	13	13	12	11	11	8	8	6	7	5	5	-6.5%
1294	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-10.1%
1295	137	135	125	121	120	121	123	123	121	119	115	113	111	121	0.0%
1296	6	5	6	6	6	6	6	5	5	5	5	5	4	5	0.1%
1297	**157**	**154**	**144**	**139**	**139**	**140**	**140**	**139**	**134**	**131**	**126**	**124**	**121**	**131**	**-0.8%**
1298	**4190**	**4211**	**4233**	**4253**	**4272**	**4289**	**4304**	**4313**	**4335**	**4346**	**4355**	**4358**	**4350**	**4339**	**0.5%**
1299	33	33	33	33	33	33	33	33	33	32	32	32	32	32	-0.3%
1300															
1301	**4157**	**4178**	**4200**	**4220**	**4239**	**4256**	**4271**	**4280**	**4303**	**4313**	**4323**	**4325**	**4318**	**4307**	**0.5%**
1302															
1303															
1304	35	42	45	49	54	59	64	69	75	81	87	94	100	106	6.1%
1305	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-0.3%
1306	144	149	155	162	171	182	195	210	228	245	259	273	285	296	4.7%
1307	15	15	15	15	15	15	15	15	15	15	15	15	15	15	1.4%
1308	98	108	117	127	134	142	146	147	147	148	149	150	152	153	5.7%
1309	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1.8%
1310	**298**	**319**	**338**	**359**	**380**	**403**	**426**	**447**	**471**	**495**	**517**	**538**	**558**	**577**	**4.9%**
1311	224	236	246	259	274	291	308	325	344	363	380	397	412	427	4.5%
1312	**74**	**84**	**92**	**100**	**106**	**112**	**118**	**122**	**127**	**132**	**137**	**141**	**146**	**149**	**6.2%**
1313															
1314															
1315	1500	1472	1456	1431	1399	1357	1304	1259	1190	1111	1042	1019	1078	1044	-2.0%
1316	44	43	43	43	43	43	42	42	42	42	42	42	43	43	0.2%
1317	1285	1310	1324	1341	1365	1393	1427	1444	1502	1589	1664	1760	1836	1980	2.9%
1318	809	821	838	859	882	908	938	972	1011	1039	1076	1023	885	783	-0.1%
1319	834	868	894	922	948	975	1002	1027	1046	1044	1032	1036	1051	1050	3.6%
1320	16	16	16	16	16	16	16	16	16	16	16	16	16	16	-0.3%
1321	**4488**	**4530**	**4571**	**4612**	**4652**	**4692**	**4729**	**4760**	**4806**	**4841**	**4872**	**4896**	**4908**	**4916**	**0.8%**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1322	**Total Net Generation to the Grid**	**3968**	**3810**	**3965**	**3911**	**3959**	**4002**	**4010**	**4019**	**4032**	**4063**	**4100**	**4138**	**4173**	**4199**
1323															
1324	**Net Imports**	**33**	**34**	**35**	**31**	**32**	**32**	**33**	**33**	**34**	**33**	**30**	**29**	**27**	**30**
1325															
1326	**Electricity Sales by Sector**														
1327	Residential	1380	1363	1455	1357	1369	1353	1352	1349	1356	1361	1370	1381	1390	1399
1328	Commercial	1336	1323	1349	1356	1369	1384	1402	1420	1439	1460	1482	1503	1523	1542
1329	Industrial	1009	882	937	974	999	1045	1040	1039	1030	1033	1034	1036	1038	1037
1330	Transportation	7	7	7	7	7	8	8	8	9	9	9	10	10	11
1331	**Total**	**3732**	**3575**	**3749**	**3695**	**3744**	**3790**	**3802**	**3816**	**3834**	**3863**	**3895**	**3929**	**3962**	**3989**
1332	Direct Use	154	170	182	194	204	212	217	227	232	235	237	240	244	250
1333	**Total Electricity Use**	**3886**	**3745**	**3931**	**3889**	**3949**	**4002**	**4019**	**4043**	**4066**	**4098**	**4133**	**4170**	**4206**	**4238**
1334															
1335	**End-Use Prices**														
1336	**(2009 cents per kilowatthour)**														
1337	Residential	11.3	11.5	11.4	10.7	10.7	10.7	10.7	10.9	10.9	10.8	10.8	10.8	10.8	10.8
1338	Commercial	10.4	10.1	9.7	9.4	9.2	9.0	8.9	9.1	9.1	9.0	9.1	9.1	9.1	9.2
1339	Industrial	6.8	6.8	6.4	6.1	6.0	5.9	5.9	6.0	6.0	6.0	6.0	6.0	6.1	6.2
1340	Transportation	11.8	11.9	10.3	10.4	10.3	10.0	9.8	9.9	9.7	9.5	9.4	9.5	9.5	9.7
1341	**All Sectors Average**	**9.8**	**9.8**	**9.6**	**9.0**	**8.9**	**8.8**	**8.7**	**8.9**	**8.9**	**8.8**	**8.9**	**8.9**	**8.9**	**9.0**
1342	**(nominal cents per kilowatthour)**														
1343	Residential	11.2	11.5	11.5	11.0	11.1	11.3	11.5	11.9	12.1	12.3	12.6	12.8	13.1	13.4
1344	Commercial	10.3	10.1	9.8	9.6	9.5	9.5	9.6	9.9	10.1	10.3	10.6	10.8	11.1	11.4
1345	Industrial	6.8	6.8	6.5	6.2	6.2	6.2	6.3	6.6	6.7	6.8	7.0	7.2	7.4	7.6
1346	Transportation	11.7	11.9	10.4	10.7	10.6	10.6	10.5	10.8	10.8	10.8	11.0	11.3	11.6	11.9
1347	All Sectors Average	9.7	9.8	9.6	9.2	9.2	9.2	9.4	9.7	9.9	10.1	10.3	10.6	10.8	11.1
1348															
1349	**Prices by Service Category**														
1350	**(2009 cents per kilowatthour)**														
1351	Generation	6.1	6.0	5.8	5.2	5.0	4.9	4.9	5.0	5.1	5.1	5.2	5.3	5.3	5.5
1352	Transmission	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
1353	Distribution	2.9	3.0	3.1	3.1	3.1	3.1	3.1	3.0	3.0	3.0	2.9	2.8	2.8	2.8
1354	**(nominal cents per kilowatthour)**														
1355	Generation	6.1	6.0	5.8	5.3	5.2	5.2	5.2	5.5	5.7	5.8	6.0	6.2	6.5	6.7
1356	Transmission	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
1357	Distribution	2.9	3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4
1358															
1359	**Electric Power Sector Emissions 1/**														
1360	Sulfur Dioxide (million tons)	7.62	5.72	6.05	5.49	5.42	5.35	5.04	4.11	4.61	4.13	4.04	3.73	4.16	3.96

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1322	**4231**	**4262**	**4292**	**4320**	**4345**	**4368**	**4389**	**4403**	**4429**	**4445**	**4460**	**4467**	**4464**	**4456**	**0.6%**
1323															
1324	**29**	**26**	**25**	**21**	**19**	**17**	**18**	**17**	**10**	**13**	**18**	**18**	**28**	**41**	**0.7%**
1325															
1326															
1327	1411	1422	1436	1444	1455	1467	1481	1488	1500	1511	1524	1527	1533	1539	0.5%
1328	1562	1581	1600	1621	1642	1662	1682	1701	1721	1742	1761	1777	1790	1801	1.2%
1329	1034	1029	1023	1016	1004	992	977	962	948	934	919	906	894	881	0.0%
1330	11	12	13	13	14	15	16	17	17	18	19	20	21	22	4.5%
1331	**4018**	**4044**	**4071**	**4095**	**4115**	**4136**	**4156**	**4168**	**4187**	**4205**	**4223**	**4231**	**4238**	**4243**	**0.7%**
1332	257	268	279	292	306	324	341	358	377	396	413	429	444	459	3.9%
1333	**4275**	**4312**	**4350**	**4386**	**4422**	**4460**	**4497**	**4526**	**4564**	**4601**	**4636**	**4660**	**4683**	**4702**	**0.9%**
1334															
1335															
1336															
1337	10.9	11.0	11.1	11.2	11.3	11.4	11.6	11.7	11.8	11.9	12.1	12.4	12.7	13.0	0.5%
1338	9.3	9.4	9.5	9.5	9.7	9.8	9.9	10.1	10.1	10.2	10.3	10.6	11.0	11.4	0.5%
1339	6.2	6.3	6.4	6.5	6.6	6.7	6.8	7.0	7.1	7.2	7.4	7.6	7.9	8.2	0.8%
1340	9.8	10.1	10.3	10.5	10.8	11.0	11.3	11.5	11.7	11.9	12.2	12.7	13.3	13.8	0.6%
1341	**9.0**	**9.2**	**9.3**	**9.4**	**9.5**	**9.6**	**9.8**	**9.9**	**10.0**	**10.1**	**10.3**	**10.6**	**11.0**	**11.3**	**0.6%**
1342															
1343	13.6	14.0	14.4	14.8	15.2	15.6	16.1	16.6	17.0	17.5	18.1	18.9	19.9	20.8	2.3%
1344	11.6	11.9	12.3	12.6	13.0	13.4	13.8	14.3	14.7	15.0	15.5	16.3	17.2	18.1	2.3%
1345	7.8	8.1	8.3	8.5	8.9	9.2	9.5	9.9	10.3	10.6	11.1	11.7	12.4	13.1	2.6%
1346	12.3	12.8	13.4	13.9	14.5	15.1	15.8	16.4	17.0	17.6	18.4	19.5	20.7	22.0	2.4%
1347	11.3	11.7	12.0	12.4	12.8	13.2	13.6	14.1	14.5	14.9	15.5	16.3	17.1	18.1	2.4%
1348															
1349															
1350															
1351	5.5	5.7	5.8	6.0	6.1	6.3	6.5	6.6	6.8	6.9	7.1	7.4	7.7	8.1	1.1%
1352	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8%
1353	2.7	2.7	2.6	2.6	2.6	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	-0.9%
1354															
1355	6.9	7.3	7.6	7.9	8.2	8.6	9.0	9.4	9.8	10.1	10.6	11.3	12.0	12.9	3.0%
1356	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	2.6%
1357	3.4	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.8	3.8	0.9%
1358															
1359															
1360	3.46	3.50	3.40	3.39	3.32	3.54	3.25	3.52	3.49	3.26	2.83	2.89	3.16	2.68	-2.9%

cesbingbk.d100611a	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Nitrogen Oxide (million tons)	3.01	1.99	2.60	2.24	2.21	2.17	2.10	1.76	1.86	1.88	1.86	1.85	1.91	1.85
Mercury (tons)	45.27	40.67	40.99	38.27	38.48	39.07	38.34	22.04	22.53	21.21	21.41	21.06	21.69	20.82

1/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

2/ Includes plants that only produce electricity.

3/ Includes electricity generation from fuel cells.

4/ Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2009 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy, (Washington, DC, May 2007).

5/ Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.

6/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).

7/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

8/ Includes refinery gas and still gas.

9/ Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.

10/ Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

11/ Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 electric power sector generation; sales to utilities; net imports; electricity sales; electricity end-use prices; and emissions: U.S. Energy Information Administration (EIA), Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010) and supporting databases. 2008 and 2009 prices: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a. Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

9. Electricity Generating Capacity

(gigawatts)

Net Summer Capacity 1/	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1361	1.86	1.80	1.77	1.76	1.73	1.69	1.64	1.59	1.51	1.42	1.33	1.35	1.42	1.37	-1.4%
1362	20.99	20.24	19.91	19.36	19.40	18.57	17.96	17.09	15.95	15.12	13.72	13.66	15.18	14.50	-3.9%
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1402															**2009-**
1403	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1404															
1405	**Electric Power Sector 2/**														
1406	**Power Only 3/**														
1407	Coal	304.4	308.2	313.5	315.0	318.5	317.4	317.3	289.2	286.0	280.1	271.9	269.9	269.5	268.8
1408	Oil and Natural Gas Steam 4/	114.6	114.0	113.2	112.5	112.5	112.2	103.9	97.7	91.9	89.0	87.4	87.2	87.2	87.2
1409	Combined Cycle	157.1	165.4	166.0	168.4	170.4	170.4	170.4	171.4	172.0	172.9	175.1	177.6	182.6	188.3
1410	Combustion Turbine/Diesel	131.7	134.6	135.5	136.0	136.0	137.5	136.8	135.0	132.6	131.5	131.0	130.6	130.6	130.5
1411	Nuclear Power 5/	100.6	101.0	101.1	101.2	102.4	104.5	105.0	105.7	101.8	101.1	102.4	103.7	103.9	103.1
1412	Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
1413	Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1414	Renewable Sources 6/	109.7	116.3	122.4	127.8	145.1	148.6	150.2	150.7	151.0	151.8	151.9	151.9	152.1	152.1
1415	Distributed Generation (Natural Gas) 7/	0.0	0.0	0.0	0.0	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
1416	**Total**	**939.8**	**961.5**	**973.4**	**982.8**	**1006.9**	**1012.8**	**1005.7**	**971.9**	**957.4**	**948.7**	**941.8**	**943.1**	**948.1**	**952.3**
1417	**Combined Heat and Power 8/**														
1418	Coal	4.7	4.7	4.6	4.6	4.6	4.6	4.6	4.3	4.2	4.2	3.5	3.5	3.5	3.5
1419	Oil and Natural Gas Steam 4/	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
1420	Combined Cycle	31.8	31.8	32.3	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8
1421	Combustion Turbine/Diesel	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
1422	Renewable Sources 6/	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
1423	**Total**	**40.4**	**40.4**	**40.9**	**41.5**	**41.5**	**41.5**	**41.5**	**41.1**	**41.0**	**41.0**	**40.3**	**40.3**	**40.3**	**40.3**
1424															
1425	**Cumulative Planned Additions 9/**														
1426	Coal	0.0	0.0	5.7	7.8	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
1427	Oil and Natural Gas Steam 4/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1428	Combined Cycle	0.0	0.0	1.0	4.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
1429	Combustion Turbine/Diesel	0.0	0.0	1.3	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
1430	Nuclear Power	0.0	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
1431	Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1432	Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1433	Renewable Sources 6/	0.0	0.0	0.0	0.2	0.4	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9
1434	Distributed Generation 7/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1435	**Total**	**0.0**	**0.0**	**7.9**	**14.3**	**20.3**	**21.7**	**21.7**	**21.7**	**21.7**	**21.7**	**21.8**	**21.8**	**21.8**	**21.8**
1436	**Cumulative Unplanned Additions 9/**														
1437	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	2.0	2.0	2.0	2.0
1438	Oil and Natural Gas Steam 4/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1439	Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.5	2.5	4.7	7.1	12.1	17.9
1440	Combustion Turbine/Diesel	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
1441	Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.6	3.9	5.9	5.9
1442	Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1404															
1405															
1406															
1407	268.6	267.5	267.5	267.3	266.8	266.3	265.1	263.7	261.8	258.6	255.3	252.5	249.4	241.9	-0.9%
1408	87.1	86.4	84.5	84.5	83.5	83.5	83.5	83.5	83.5	83.5	83.5	82.8	82.8	81.8	-1.3%
1409	194.9	202.5	211.3	216.4	219.4	223.8	226.8	228.8	234.9	245.0	254.5	266.1	273.0	282.7	2.1%
1410	130.1	129.2	129.1	129.0	128.9	128.9	129.0	129.1	129.1	129.2	129.9	130.4	131.8	133.0	0.0%
1411	101.9	103.9	106.2	108.9	111.8	115.2	119.1	123.5	128.6	134.5	141.3	149.0	146.1	155.0	1.7%
1412	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	0.0%
1413	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1414	152.2	158.7	162.9	167.8	173.3	179.6	186.9	195.3	204.8	207.5	207.7	207.8	207.9	210.0	2.3%
1415	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.9	- -
1416	**957.0**	**970.4**	**983.8**	**996.1**	**1006.0**	**1019.6**	**1032.8**	**1046.3**	**1065.2**	**1080.7**	**1094.7**	**1111.1**	**1113.6**	**1127.2**	**0.6%**
1417															
1418	3.5	3.5	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-1.2%
1419	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
1420	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	32.8	0.1%
1421	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.2%
1422	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
1423	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.3**	**40.2**	**0.0%**
1424															
1425															
1426	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	- -
1427	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1428	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	- -
1429	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	- -
1430	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	- -
1431	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1432	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1433	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	- -
1434	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1435	**21.9**	**21.9**	**21.9**	**21.9**	**21.9**	**22.0**	**22.0**	**22.0**	**22.0**	**22.0**	**22.1**	**22.1**	**22.1**	**22.1**	- -
1436															
1437	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	- -
1438	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1439	24.5	32.1	40.8	46.0	48.9	53.3	56.4	58.4	64.5	74.5	84.1	95.6	102.6	112.3	- -
1440	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.8	1.8	1.8	2.6	3.0	4.4	5.7	- -
1441	5.9	7.9	10.2	12.8	15.8	19.1	23.0	27.5	32.6	38.5	45.2	53.0	54.5	63.4	- -
1442	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources 6/	0.0	0.0	6.0	11.4	28.4	31.6	33.2	33.7	34.0	34.8	34.8	34.8	35.0	35.0
Distributed Generation 7/	0.0	0.0	0.0	0.0	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Total	**0.0**	**0.0**	**6.0**	**11.4**	**28.6**	**33.5**	**35.1**	**36.6**	**38.4**	**42.5**	**46.0**	**49.8**	**57.0**	**62.7**
Cumulative Electric Power Sector Addi	**0.0**	**0.0**	**14.0**	**25.7**	**48.9**	**55.2**	**56.8**	**58.3**	**60.1**	**64.2**	**67.8**	**71.6**	**78.8**	**84.6**
Cumulative Retirements 10/														
Coal	0.0	0.0	0.5	1.0	1.3	2.4	2.4	30.9	35.2	42.1	51.0	53.0	53.4	54.1
Oil and Natural Gas Steam 4/	0.0	0.0	0.9	1.5	1.5	1.8	10.1	16.3	22.2	25.0	26.7	26.8	26.8	26.8
Combined Cycle	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Combustion Turbine/Diesel	0.0	0.0	0.2	0.5	0.5	0.5	1.3	3.0	5.4	6.6	7.1	7.4	7.4	7.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	6.1	6.1	6.1	7.8	8.7
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources 6/	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**0.0**	**1.6**	**3.4**	**3.7**	**5.2**	**14.3**	**50.7**	**67.3**	**80.2**	**91.3**	**93.7**	**96.0**	**97.5**
Total Electric Power Sector Capacity	**980.2**	**1001.9**	**1014.4**	**1024.2**	**1048.4**	**1054.3**	**1047.2**	**1013.0**	**998.5**	**989.7**	**982.1**	**983.5**	**988.5**	**992.7**
End-Use Generators 11/														
Coal	3.5	4.0	4.0	4.0	3.9	3.9	3.9	4.8	5.0	5.0	5.0	5.0	5.1	5.2
Petroleum	0.9	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Natural Gas	14.8	16.1	17.8	19.1	19.7	20.3	20.8	21.1	21.5	21.7	22.0	22.2	22.6	22.9
Other Gaseous Fuels	1.9	1.9	1.9	1.9	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Renewable Sources 6/	6.7	7.5	9.0	11.0	12.8	14.4	15.5	17.3	18.9	19.4	19.8	20.4	21.2	22.2
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**28.4**	**31.5**	**34.6**	**37.9**	**41.0**	**43.2**	**44.8**	**47.9**	**50.0**	**50.7**	**51.4**	**52.2**	**53.5**	**55.0**
Cumulative Capacity Additions 9/	**0.0**	**0.0**	**3.1**	**6.4**	**9.5**	**11.7**	**13.3**	**16.4**	**18.5**	**19.2**	**19.9**	**20.7**	**22.0**	**23.5**

1/ Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
2/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
3/ Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
4/ Includes oil-, gas-, and dual-fired capacity.
5/ Nuclear capacity includes 3.8 gigawatts of uprates through 2035.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
1443	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1444	35.1	41.5	45.7	50.6	56.1	62.4	69.7	78.0	87.5	90.2	90.3	90.4	90.6	92.6	- -
1445	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.9	- -
1446	**69.4**	**85.5**	**100.8**	**113.4**	**124.8**	**138.9**	**153.2**	**168.1**	**188.9**	**207.5**	**224.8**	**244.7**	**254.8**	**276.9**	- -
1447	**91.3**	**107.4**	**122.7**	**135.3**	**146.7**	**160.8**	**175.2**	**190.1**	**210.9**	**229.6**	**246.9**	**266.8**	**276.9**	**299.0**	- -
1448															
1449															
1450	54.3	55.4	55.5	55.7	56.2	56.7	57.8	59.3	61.1	64.3	67.6	70.4	73.6	81.1	- -
1451	27.0	27.7	29.5	29.5	30.5	30.5	30.5	30.5	30.5	30.5	30.5	31.2	31.2	32.2	- -
1452	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	- -
1453	8.0	8.9	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	- -
1454	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	14.3	14.3	- -
1455	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1456	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1457	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	- -
1458	**99.6**	**102.3**	**104.2**	**104.6**	**106.1**	**106.6**	**107.7**	**109.2**	**111.0**	**114.2**	**117.5**	**121.1**	**128.7**	**137.3**	- -
1459															
1460	**997.4**	**1010.8**	**1024.1**	**1036.4**	**1046.3**	**1059.9**	**1073.1**	**1086.6**	**1105.5**	**1121.0**	**1135.0**	**1151.4**	**1153.9**	**1167.4**	**0.6%**
1461															
1462															
1463	5.6	6.5	7.0	7.5	8.1	8.8	9.5	10.2	11.0	11.8	12.6	13.5	14.3	15.2	5.3%
1464	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	0.2%
1465	23.4	24.0	24.7	25.7	26.9	28.4	30.1	32.2	34.6	36.7	38.7	40.5	42.1	43.6	3.9%
1466	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	1.3%
1467	23.4	24.7	25.9	27.2	28.3	29.5	30.2	30.5	30.7	30.9	31.2	31.6	31.9	32.3	5.7%
1468	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
1469	**57.0**	**59.7**	**62.3**	**65.1**	**68.0**	**71.2**	**74.4**	**77.5**	**80.8**	**84.1**	**87.2**	**90.2**	**93.0**	**95.7**	**4.4%**
1470															
1471	**25.5**	**28.2**	**30.8**	**33.6**	**36.5**	**39.7**	**42.9**	**46.0**	**49.3**	**52.6**	**55.7**	**58.7**	**61.5**	**64.2**	- -
1472															
1473															
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1480															
1481															
1482															

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

6/ Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.

7/ Primarily peak-load capacity fueled by natural gas.

8/ Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).

9/ Cumulative additions after December 31, 2009.

10/ Cumulative retirements after December 31, 2009.

11/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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1523															
1524															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1525	**10. Electricity Trade**														
1526	**(billion kilowatthours, unless otherwise noted)**														
1527															
1528	*Electricity Trade*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1529															
1530	**Interregional Electricity Trade**														
1531															
1532	**Gross Domestic Sales**														
1533	Firm Power	181.3	185.6	182.2	177.0	176.7	175.7	175.5	172.7	169.7	158.2	146.6	135.0	123.5	111.9
1534	Economy	303.1	279.1	254.5	267.3	308.0	281.1	263.1	234.6	215.6	207.4	187.2	179.4	175.4	179.1
1535	**Total**	**484.4**	**464.7**	**436.7**	**444.3**	**484.8**	**456.8**	**438.7**	**407.3**	**385.4**	**365.5**	**333.8**	**314.4**	**298.8**	**291.0**
1536															
1537	**Gross Domestic Sales (million 2009 dollars)**														
1538	Firm Power	10738.4	10992.8	10792.1	10483.3	10470.0	10407.5	10398.5	10232.4	10054.3	9369.2	8684.1	7998.9	7313.8	6628.7
1539	Economy	24158.0	11224.9	11026.2	10796.1	11424.3	10408.8	9798.1	8964.9	8049.1	7825.0	7219.8	6987.9	7007.3	7389.4
1540	**Total**	**34896.4**	**22217.8**	**21818.2**	**21279.4**	**21894.2**	**20816.2**	**20196.6**	**19197.3**	**18103.4**	**17194.2**	**15903.8**	**14986.9**	**14321.1**	**14018.1**
1541															
1542	**International Electricity Trade**														
1543	**Imports from Canada and Mexico**														
1544	Firm Power	19.9	19.3	29.8	31.3	30.9	30.5	28.8	28.4	27.9	25.1	22.4	19.6	16.9	14.1
1545	Economy	37.1	33.1	20.8	16.5	19.7	21.2	24.1	24.5	25.7	27.5	27.0	28.1	29.1	34.3
1546	**Total**	**57.0**	**52.4**	**50.6**	**47.8**	**50.6**	**51.6**	**52.9**	**52.9**	**53.5**	**52.6**	**49.4**	**47.7**	**46.0**	**48.4**
1547															
1548	**Exports to Canada and Mexico**														
1549	Firm Power	3.3	3.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.6	0.5	0.4
1550	Economy	20.7	14.7	15.1	16.1	17.5	18.3	18.8	18.7	18.6	18.4	18.3	18.2	18.1	18.0
1551	**Total**	**24.1**	**18.1**	**16.0**	**17.0**	**18.4**	**19.2**	**19.7**	**19.6**	**19.4**	**19.2**	**19.0**	**18.8**	**18.6**	**18.4**
1552															
1553															
1554															
1555															
1556	- - = Not applicable.														
1557	Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and														
1558	2009 are model results and may differ slightly from official EIA data reports. Firm Power Sales are														
1559	capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected														
1560	electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier														
1561	in accordance with prior agreements or under specified conditions.														
1562	Sources: 2008 and 2009 interregional firm electricity trade data: North American														
1563	Electric Reliability Council (NERC), Electricity Sales and Demand Database 2008.														
1564	2008 and 2009 Mexican electricity trade data: U.S. Energy Information Administration (EIA),														
1565	Electric Power Annual 2009, DOE/EIA-0348(2009) (Washington, DC, January 2011).														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1525															
1526															
1527															**2009-**
1528	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
1529															
1530															
1531															
1532															
1533	100.3	88.8	77.2	65.6	54.1	54.1	54.1	54.1	54.1	54.1	54.1	54.1	54.1	54.1	-4.6%
1534	175.4	183.3	175.4	179.0	185.1	183.2	184.9	187.4	158.2	118.2	132.6	84.5	70.2	99.3	-3.9%
1535	**275.7**	**272.1**	**252.6**	**244.7**	**239.2**	**237.3**	**239.0**	**241.5**	**212.3**	**172.2**	**186.6**	**138.6**	**124.3**	**153.4**	**-4.2%**
1536															
1537															
1538	5943.6	5258.5	4573.4	3888.3	3203.2	3203.2	3203.2	3203.2	3203.2	3203.2	3203.2	3203.2	3203.2	3203.2	-4.6%
1539	7550.5	8127.4	8081.3	8402.8	8873.5	9032.7	9444.8	9821.6	8593.2	6836.6	8225.4	5872.5	5252.3	7770.0	-1.4%
1540	**13494.1**	**13385.9**	**12654.7**	**12291.1**	**12076.7**	**12235.9**	**12647.9**	**13024.8**	**11796.3**	**10039.8**	**11428.5**	**9075.7**	**8455.5**	**10973.1**	**-2.7%**
1541															
1542															
1543															
1544	11.4	8.6	5.9	3.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-14.0%
1545	35.7	35.1	36.6	35.7	35.6	34.3	34.8	33.9	26.3	29.4	34.3	34.0	44.4	56.8	2.1%
1546	**47.1**	**43.8**	**42.5**	**38.8**	**36.0**	**34.7**	**35.2**	**34.3**	**26.6**	**29.8**	**34.7**	**34.4**	**44.7**	**57.2**	**0.3%**
1547															
1548															
1549	0.4	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
1550	17.9	17.7	17.6	17.5	17.4	17.3	17.2	17.1	17.0	16.8	16.7	16.6	16.5	16.4	0.4%
1551	**18.2**	**18.0**	**17.8**	**17.6**	**17.4**	**17.3**	**17.2**	**17.1**	**17.0**	**16.8**	**16.7**	**16.6**	**16.5**	**16.4**	**-0.4%**
1552															
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2008 Canadian international electricity trade data:
National Energy Board, Electricity Exports and Imports Statistics, 2008.
2009 Canadian international electricity trade data:
National Energy Board, Electricity Exports and Imports Statistics, 2009.
Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

11. Liquid Fuels Supply and Disposition

(million barrels per day, unless otherwise noted)

Supply and Disposition	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Crude Oil														
Domestic Crude Production 1/	4.96	5.36	5.51	5.46	5.38	5.58	5.75	5.82	5.96	6.08	6.11	6.12	6.09	6.07
Alaska	0.69	0.65	0.61	0.59	0.55	0.53	0.52	0.49	0.47	0.45	0.42	0.40	0.42	0.45
Lower 48 States	4.28	4.71	4.90	4.87	4.83	5.05	5.24	5.33	5.49	5.64	5.68	5.72	5.67	5.63
Net Imports	9.75	8.97	9.17	9.13	9.00	8.97	8.80	8.67	8.50	8.36	8.30	8.24	8.23	8.27
Gross Imports	9.78	9.01	9.21	9.17	9.03	9.00	8.83	8.70	8.53	8.39	8.33	8.27	8.26	8.30
Exports	0.03	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Crude Supply 2/	-0.06	0.01	0.01	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.66**	**14.33**	**14.69**	**14.66**	**14.38**	**14.55**	**14.55**	**14.49**	**14.46**	**14.44**	**14.41**	**14.36**	**14.32**	**14.34**
Other Petroleum Supply	**4.10**	**3.59**	**3.36**	**3.43**	**4.25**	**4.34**	**4.35**	**4.45**	**4.42**	**4.34**	**4.34**	**4.36**	**4.38**	**4.45**
Natural Gas Plant Liquids	1.78	1.91	1.96	1.95	2.11	2.13	2.15	2.30	2.26	2.28	2.33	2.38	2.45	2.52
Net Product Imports	1.39	0.75	0.37	0.48	1.12	1.19	1.19	1.15	1.14	1.04	1.00	0.96	0.93	0.93
Gross Refined Product Imports 3/	1.55	1.27	0.97	1.04	1.04	1.06	1.05	1.04	1.05	0.99	0.99	0.98	0.97	0.96
Unfinished Oil Imports	0.76	0.68	0.62	0.66	0.78	0.81	0.81	0.80	0.79	0.79	0.79	0.78	0.78	0.78
Blending Component Imports	0.79	0.72	0.70	0.69	0.78	0.80	0.80	0.81	0.81	0.80	0.80	0.80	0.80	0.81
Exports	1.71	1.92	1.92	1.92	1.48	1.48	1.47	1.49	1.50	1.54	1.58	1.60	1.61	1.62
Refinery Processing Gain 4/	1.00	0.98	1.03	1.00	1.02	1.01	1.01	1.00	1.01	1.02	1.01	1.01	1.00	1.00
Product Stock Withdrawal	-0.07	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.76**	**0.81**	**1.01**	**1.23**	**1.25**	**1.29**	**1.33**	**1.38**	**1.43**	**1.54**	**1.61**	**1.68**	**1.77**	**1.72**
Supply from Renewable Sources	0.66	0.76	0.89	0.95	1.05	1.08	1.09	1.12	1.16	1.23	1.30	1.37	1.46	1.42
Ethanol	0.64	0.73	0.86	0.90	0.98	1.00	1.02	1.03	1.05	1.11	1.18	1.24	1.31	1.26
Domestic Production	0.61	0.72	0.86	0.89	0.96	0.98	0.99	0.97	0.98	1.02	1.06	1.13	1.20	1.21
Net Imports	0.03	0.01	0.00	0.01	0.02	0.02	0.03	0.06	0.08	0.10	0.12	0.11	0.11	0.05
Biodiesel	0.02	0.02	0.02	0.05	0.06	0.07	0.06	0.08	0.09	0.10	0.10	0.10	0.10	0.10
Domestic Production	0.04	0.03	0.03	0.05	0.05	0.06	0.06	0.07	0.09	0.09	0.09	0.10	0.10	0.10

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1566															
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1575															
1576															
1577															**2009-**
1578	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
1579															
1580															
1581	6.08	6.00	5.89	5.84	5.79	5.84	5.85	5.89	5.92	6.00	6.14	6.25	6.21	6.17	0.5%
1582	0.46	0.44	0.42	0.41	0.37	0.34	0.32	0.29	0.27	0.31	0.37	0.42	0.40	0.39	-1.9%
1583	5.62	5.55	5.47	5.43	5.42	5.50	5.54	5.59	5.65	5.69	5.76	5.83	5.81	5.78	0.8%
1584	8.15	8.13	8.14	8.17	8.16	8.10	7.98	7.97	7.96	7.89	7.78	7.61	7.69	7.78	-0.5%
1585	8.19	8.16	8.17	8.20	8.19	8.13	8.01	8.00	7.99	7.93	7.81	7.65	7.73	7.82	-0.5%
1586	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-1.0%
1587	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1588	**14.24**	**14.13**	**14.04**	**14.01**	**13.95**	**13.94**	**13.83**	**13.86**	**13.88**	**13.90**	**13.92**	**13.86**	**13.90**	**13.96**	**-0.1%**
1589															
1590	**4.49**	**4.51**	**4.54**	**4.53**	**4.50**	**4.49**	**4.46**	**4.44**	**4.45**	**4.45**	**4.46**	**4.51**	**4.50**	**4.50**	**0.9%**
1591	2.63	2.74	2.85	2.88	2.90	2.93	2.96	2.96	2.99	3.05	3.06	3.08	3.08	3.09	1.9%
1592	0.90	0.84	0.79	0.77	0.74	0.69	0.65	0.62	0.60	0.54	0.54	0.56	0.56	0.56	-1.1%
1593	0.95	0.93	0.90	0.89	0.88	0.85	0.82	0.81	0.78	0.74	0.74	0.77	0.78	0.78	-1.9%
1594	0.77	0.75	0.74	0.74	0.73	0.73	0.72	0.72	0.72	0.72	0.73	0.72	0.73	0.73	0.3%
1595	0.81	0.80	0.79	0.79	0.79	0.80	0.79	0.80	0.80	0.81	0.81	0.82	0.82	0.83	0.5%
1596	1.63	1.64	1.64	1.66	1.66	1.68	1.67	1.70	1.71	1.73	1.74	1.75	1.76	1.78	-0.3%
1597	0.96	0.93	0.90	0.89	0.87	0.87	0.85	0.86	0.86	0.87	0.87	0.87	0.86	0.86	-0.5%
1598	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1599	**1.87**	**2.02**	**2.18**	**2.30**	**2.40**	**2.50**	**2.68**	**2.75**	**2.84**	**2.93**	**3.00**	**3.11**	**3.18**	**3.23**	**5.5%**
1600	1.56	1.67	1.81	1.91	1.98	2.05	2.19	2.22	2.26	2.31	2.34	2.41	2.44	2.45	4.6%
1601	1.36	1.44	1.54	1.60	1.62	1.63	1.72	1.73	1.72	1.74	1.75	1.78	1.78	1.79	3.5%
1602	1.23	1.30	1.39	1.44	1.45	1.44	1.52	1.50	1.50	1.50	1.50	1.52	1.53	1.53	2.9%
1603	0.13	0.14	0.15	0.16	0.17	0.19	0.20	0.22	0.23	0.24	0.26	0.25	0.25	0.26	12.2%
1604	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.12	0.13	0.13	0.13	0.13	0.13	0.13	7.2%
1605	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13	5.3%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1606	Net Imports	-0.02	-0.01	-0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1607	Other Biomass-derived Liquids 5/	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.05	0.06
1608	Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1609	Liquids from Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.05	0.05	0.05	0.05	0.06
1610	Other 6/	0.10	0.05	0.12	0.28	0.20	0.21	0.25	0.22	0.22	0.26	0.26	0.26	0.26	0.24
1611															
1612	**Total Primary Supply 7/**	**19.51**	**18.73**	**19.05**	**19.32**	**19.87**	**20.17**	**20.24**	**20.32**	**20.31**	**20.32**	**20.36**	**20.40**	**20.47**	**20.51**
1613															
1614	**Liquid Fuels Consumption**														
1615	**by Fuel**														
1616	Liquefied Petroleum Gases	2.04	2.13	2.13	2.10	2.26	2.30	2.32	2.30	2.28	2.27	2.27	2.26	2.27	2.27
1617	E85 8/	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.07	0.12	0.16	0.21	0.14
1618	Motor Gasoline 9/	8.99	9.00	9.02	9.09	9.34	9.39	9.40	9.40	9.39	9.33	9.26	9.21	9.16	9.22
1619	Jet Fuel 10/	1.54	1.39	1.40	1.41	1.52	1.52	1.53	1.55	1.56	1.57	1.59	1.60	1.62	1.63
1620	Distillate Fuel Oil 11/	3.95	3.63	3.73	3.75	3.98	4.12	4.12	4.10	4.13	4.16	4.20	4.23	4.27	4.29
1621	of which: Diesel	3.44	3.18	3.24	3.26	3.50	3.64	3.66	3.65	3.68	3.72	3.77	3.81	3.85	3.88
1622	Residual Fuel Oil	0.62	0.51	0.53	0.55	0.60	0.60	0.59	0.60	0.60	0.60	0.60	0.60	0.60	0.60
1623	Other 12/	2.38	2.15	2.16	2.21	2.29	2.36	2.40	2.46	2.44	2.42	2.41	2.40	2.39	2.39
1624	**by Sector**														
1625	Residential and Commercial	1.06	1.04	1.00	1.00	0.99	0.97	0.96	0.95	0.95	0.93	0.93	0.92	0.91	0.90
1626	Industrial 13/	4.69	4.25	4.37	4.50	4.78	4.91	4.96	5.00	4.95	4.93	4.91	4.90	4.89	4.89
1627	Transportation	13.87	13.61	13.74	13.88	14.03	14.22	14.26	14.27	14.31	14.37	14.42	14.46	14.52	14.55
1628	Electric Power 14/	0.21	0.18	0.20	0.20	0.20	0.20	0.19	0.20	0.19	0.20	0.20	0.19	0.19	0.20
1629	**Total**	**19.52**	**18.81**	**18.98**	**19.10**	**19.99**	**20.30**	**20.38**	**20.42**	**20.41**	**20.43**	**20.45**	**20.47**	**20.52**	**20.54**
1630															
1631	Discrepancy 15/	-0.01	-0.08	0.07	0.21	-0.12	-0.13	-0.14	-0.10	-0.10	-0.11	-0.09	-0.07	-0.06	-0.04
1632															
1633															
1634	Domestic Refinery Distillation Capacity 16/	17.6	17.7	17.6	17.6	17.6	17.6	17.5	17.5	17.3	17.1	16.9	16.7	16.5	16.4
1635	Capacity Utilization Rate (percent) 17/	85.0	83.0	86.0	85.0	83.3	84.4	84.9	84.7	85.3	86.1	87.2	87.9	88.8	89.6
1636	Net Import Share of Product Supplied (per	57.2	51.9	50.0	49.7	51.1	50.5	49.5	48.6	47.9	46.7	46.3	45.7	45.3	45.1
1637	**Net Expenditures for Imports of Crude Oil and**														
1638	Petroleum Products (billion 2009 dollars)	272.69	203.66	215.64	268.30	281.44	288.83	291.32	294.49	297.89	303.32	310.56	315.03	321.30	324.47
1639															
1640															
1641															
1642															
1643															
1644	1/ Includes lease condensate.														
1645	2/ Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1606	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1607	0.08	0.11	0.14	0.19	0.24	0.30	0.34	0.38	0.42	0.45	0.46	0.51	0.53	0.54	- -
1608	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1609	0.08	0.12	0.14	0.17	0.20	0.23	0.26	0.29	0.33	0.37	0.41	0.44	0.48	0.52	- -
1610	0.24	0.23	0.23	0.22	0.22	0.23	0.23	0.24	0.25	0.25	0.25	0.25	0.25	0.25	6.2%
1611															
1612	**20.60**	**20.66**	**20.76**	**20.83**	**20.86**	**20.93**	**20.97**	**21.05**	**21.17**	**21.29**	**21.38**	**21.48**	**21.59**	**21.69**	**0.6%**
1613															
1614															
1615															
1616	2.27	2.27	2.27	2.26	2.24	2.23	2.22	2.21	2.20	2.19	2.17	2.16	2.14	2.13	0.0%
1617	0.28	0.41	0.56	0.64	0.74	0.67	0.88	0.80	0.76	0.78	0.79	0.78	0.78	0.78	25.9%
1618	9.10	9.00	8.88	8.84	8.77	8.88	8.73	8.85	8.97	9.02	9.09	9.16	9.23	9.31	0.1%
1619	1.64	1.65	1.67	1.68	1.69	1.70	1.70	1.71	1.72	1.73	1.73	1.74	1.74	1.75	0.9%
1620	4.33	4.35	4.38	4.41	4.44	4.47	4.49	4.52	4.56	4.59	4.62	4.66	4.71	4.75	1.0%
1621	3.92	3.95	3.99	4.03	4.06	4.09	4.12	4.15	4.19	4.24	4.27	4.31	4.36	4.40	1.3%
1622	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.7%
1623	2.39	2.38	2.38	2.37	2.36	2.36	2.34	2.34	2.34	2.35	2.35	2.35	2.35	2.35	0.3%
1624															
1625	0.90	0.89	0.89	0.88	0.88	0.87	0.87	0.87	0.86	0.86	0.86	0.85	0.85	0.85	-0.8%
1626	4.89	4.88	4.88	4.86	4.84	4.81	4.78	4.76	4.75	4.74	4.72	4.71	4.69	4.67	0.4%
1627	14.63	14.69	14.78	14.87	14.95	15.03	15.13	15.22	15.35	15.48	15.60	15.70	15.83	15.96	0.6%
1628	0.20	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.4%
1629	**20.62**	**20.67**	**20.74**	**20.81**	**20.85**	**20.91**	**20.97**	**21.03**	**21.15**	**21.27**	**21.37**	**21.46**	**21.57**	**21.68**	**0.5%**
1630															
1631	-0.02	0.00	0.02	0.02	0.01	0.02	0.00	0.02	0.01	0.01	0.01	0.02	0.01	0.01	- -
1632															
1633															
1634	16.2	16.0	15.9	15.8	15.8	15.8	15.6	15.6	15.7	15.7	15.6	15.7	15.7	15.7	-0.5%
1635	89.9	90.2	90.3	90.4	90.5	90.4	90.7	90.7	90.4	90.4	91.2	90.4	90.6	90.8	0.3%
1636	44.6	44.1	43.7	43.7	43.5	42.9	42.1	41.9	41.5	40.8	40.1	39.2	39.4	39.7	-1.0%
1637															
1638	329.13	334.97	340.09	346.62	349.38	350.89	348.14	351.35	349.55	348.10	344.80	338.62	343.82	348.30	2.1%
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1646	3/ Includes other hydrocarbons and alcohols.														
1647	4/ The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total,														
1648	have a lower specific gravity than the crude oil processed.														
1649	5/ Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the production														
1650	of green diesel and gasoline.														
1651	6/ Includes domestic sources of other blending components, other hydrocarbons, and ethers.														
1652	7/ Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.														
1653	8/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address														
1654	cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of														
1655	74 percent is used for this forecast.														
1656	9/ Includes ethanol and ethers blended into gasoline.														
1657	10/ Includes only kerosene type.														
1658	11/ Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.														
1659	12/ Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas,														
1660	special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.														
1661	13/ Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.														
1662	14/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business														
1663	is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.														
1664	15/ Balancing item. Includes unaccounted for supply, losses and gains.														
1665	16/ End-of-year operable capacity.														
1666	17/ Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their														
1667	operable refining capacity in barrels per calendar day.														
1668	- - = Not applicable.														
1669	Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009														
1670	are model results and may differ slightly from official EIA data reports.														
1671	Sources: 2008 and 2009 product supplied based on: U.S. Energy Information Administration (EIA),														
1672	Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).														
1673	Other 2008 data: EIA, Petroleum Supply Annual 2008, DOE/EIA-0340(2008)/1 (Washington, DC, June 2009).														
1674	Other 2009 data: EIA, Petroleum Supply Annual 2009, DOE/EIA-0340(2009)/1 (Washington, DC, July 2010).														
1675	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
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	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
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1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
12. Petroleum Product Prices														
(2009 dollars per gallon, unless otherwise noted)														
Sector and Fuel	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Crude Oil Prices (2009 dollars per barrel)														
Imported Low-Sulfur Light Crude Oil 1/	100.51	61.66	78.03	83.21	85.74	88.09	91.43	94.48	97.48	100.35	103.06	105.65	108.03	110.28
Imported Crude Oil 1/	93.44	59.04	74.86	80.32	80.68	82.96	85.08	86.73	88.74	91.35	93.91	96.22	98.51	100.58
Delivered Sector Product Prices														
Residential														
Liquefied Petroleum Gases	2.525	2.087	2.244	2.263	2.417	2.458	2.496	2.508	2.541	2.587	2.632	2.673	2.711	2.745
Distillate Fuel Oil	3.432	2.514	2.869	3.006	2.765	2.819	2.871	2.921	3.032	3.138	3.235	3.290	3.353	3.393
Commercial														
Distillate Fuel Oil	3.010	2.205	2.514	2.630	2.490	2.542	2.594	2.644	2.750	2.851	2.945	2.999	3.061	3.105

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1728															
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1752															**2009-**
1753	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
1754															
1755															
1756	112.45	114.55	116.36	117.98	119.07	120.31	120.92	121.94	122.70	123.29	123.72	123.59	123.97	124.14	2.7%
1757	102.54	104.50	106.20	107.76	108.71	109.84	110.08	111.04	111.65	112.03	112.24	112.08	112.49	112.67	2.5%
1758															
1759															
1760															
1761															
1762	2.778	2.811	2.839	2.865	2.880	2.900	2.903	2.921	2.931	2.936	2.936	2.928	2.930	2.929	1.3%
1763	3.453	3.514	3.571	3.614	3.653	3.678	3.725	3.750	3.717	3.729	3.738	3.804	3.824	3.838	1.6%
1764															
1765															
1766	3.169	3.231	3.286	3.326	3.368	3.391	3.441	3.463	3.420	3.431	3.441	3.495	3.514	3.526	1.8%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1767	Residual Fuel Oil	2.366	2.013	2.068	2.233	1.743	1.833	1.918	1.981	2.048	2.117	2.182	2.211	2.272	2.322
1768	Residual Fuel Oil (2009 dollars per barre	99.36	84.54	86.85	93.80	73.20	76.98	80.54	83.22	86.02	88.89	91.65	92.86	95.43	97.54
1769															
1770	**Industrial 2/**														
1771	Liquefied Petroleum Gases	2.139	1.744	1.872	2.364	1.869	1.912	1.948	1.960	1.991	2.038	2.084	2.126	2.165	2.200
1772	Distillate Fuel Oil	3.108	2.281	2.599	2.716	2.484	2.538	2.594	2.647	2.751	2.853	2.949	3.003	3.067	3.112
1773	Residual Fuel Oil	2.434	1.804	1.844	1.999	2.035	2.082	2.152	2.209	2.275	2.332	2.397	2.437	2.494	2.531
1774	Residual Fuel Oil (2009 dollars per barre	102.24	75.79	77.43	83.94	85.47	87.46	90.38	92.79	95.55	97.95	100.68	102.35	104.77	106.30
1775															
1776	**Transportation**														
1777	Liquefied Petroleum Gases	2.591	2.161	2.308	2.329	2.486	2.525	2.562	2.574	2.606	2.652	2.697	2.737	2.774	2.808
1778	Ethanol (E85) 3/	3.355	1.945	2.362	2.475	2.249	2.370	2.446	2.500	2.547	2.515	2.626	2.695	2.726	2.733
1779	Ethanol Wholesale Price	2.475	2.028	1.643	1.643	2.482	1.950	1.988	2.550	2.554	2.544	2.571	2.564	2.562	2.539
1780	Motor Gasoline 4/	3.327	2.349	2.684	2.802	2.822	2.971	3.063	3.131	3.188	3.262	3.310	3.335	3.386	3.387
1781	Jet Fuel 5/	3.146	1.700	2.128	2.279	2.442	2.492	2.524	2.560	2.662	2.759	2.850	2.903	2.963	3.009
1782	Diesel Fuel (distillate fuel oil) 6/	3.837	2.441	2.889	3.028	2.917	2.969	3.023	3.075	3.178	3.281	3.379	3.448	3.518	3.528
1783	Residual Fuel Oil	2.181	1.582	1.620	1.755	1.711	1.757	1.823	1.886	1.961	2.013	2.079	2.119	2.175	2.223
1784	Residual Fuel Oil (2009 dollars per barre	91.59	66.44	68.03	73.70	71.85	73.78	76.58	79.23	82.38	84.55	87.33	89.00	91.33	93.37
1785															
1786	**Electric Power 7/**														
1787	Distillate Fuel Oil	2.713	1.988	2.272	2.388	2.170	2.221	2.269	2.310	2.408	2.512	2.602	2.659	2.714	2.756
1788	Residual Fuel Oil	2.208	1.342	1.711	1.815	1.786	1.835	1.903	1.922	1.993	2.048	2.114	2.151	2.207	2.251
1789	Residual Fuel Oil (2009 dollars per barre	92.73	56.36	71.85	76.22	75.01	77.06	79.94	80.72	83.72	86.02	88.78	90.36	92.70	94.55
1790															
1791	**Refined Petroleum Product Prices 8/**														
1792	Liquefied Petroleum Gases	1.774	1.477	1.528	1.750	1.748	1.780	1.812	1.824	1.855	1.897	1.939	1.976	2.011	2.042
1793	Motor Gasoline 4/	3.305	2.344	2.679	2.799	2.822	2.971	3.063	3.131	3.188	3.261	3.310	3.335	3.386	3.387
1794	Jet Fuel 5/	3.146	1.700	2.128	2.279	2.442	2.492	2.524	2.560	2.662	2.759	2.850	2.903	2.963	3.009
1795	Distillate Fuel Oil	3.648	2.408	2.822	2.960	2.803	2.875	2.931	2.985	3.090	3.193	3.292	3.359	3.429	3.447
1796	Residual Fuel Oil	2.228	1.576	1.685	1.822	1.771	1.821	1.888	1.941	2.013	2.067	2.132	2.170	2.227	2.273
1797	Residual Fuel Oil (2009 dollars per barre	93.58	66.20	70.76	76.52	74.39	76.47	79.30	81.52	84.54	86.79	89.55	91.16	93.51	95.45
1798	**Average**	**3.10**	**2.15**	**2.47**	**2.60**	**2.59**	**2.69**	**2.76**	**2.82**	**2.89**	**2.96**	**3.03**	**3.06**	**3.12**	**3.13**
1799															
1800															
1801	**Prices in Nominal Dollars**														
1802	**Crude Oil Prices (nominal dollars per barrel)**														
1803	Imported Low-Sulfur Light Crude Oil 1/	99.57	61.66	78.71	85.05	88.69	92.70	97.93	103.32	108.78	114.36	119.93	125.36	130.73	135.89
1804	Imported Crude Oil 1/	92.57	59.04	75.52	82.10	83.45	87.30	91.14	94.84	99.02	104.10	109.28	114.18	119.21	123.94
1805															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1767	2.399	2.500	2.532	2.559	2.578	2.602	2.609	2.618	2.630	2.638	2.653	2.668	2.688	2.707	1.1%
1768	100.76	105.01	106.32	107.47	108.29	109.27	109.58	109.97	110.44	110.78	111.41	112.05	112.90	113.68	1.1%
1769															
1770															
1771	2.235	2.269	2.298	2.324	2.338	2.357	2.358	2.374	2.384	2.388	2.390	2.381	2.381	2.380	1.2%
1772	3.182	3.249	3.306	3.345	3.392	3.412	3.469	3.488	3.430	3.441	3.451	3.503	3.522	3.536	1.7%
1773	2.588	2.649	2.696	2.732	2.751	2.772	2.784	2.783	2.793	2.774	2.780	2.825	2.838	2.844	1.8%
1774	108.69	111.27	113.23	114.75	115.54	116.43	116.93	116.88	117.30	116.51	116.75	118.66	119.21	119.47	1.8%
1775															
1776															
1777	2.840	2.873	2.901	2.926	2.941	2.960	2.963	2.980	2.990	2.994	2.994	2.985	2.986	2.984	1.2%
1778	2.690	2.753	2.795	2.818	2.873	2.879	2.927	2.924	2.869	2.877	2.889	2.925	2.943	2.954	1.6%
1779	2.579	2.563	2.564	2.546	2.510	2.475	2.463	2.452	2.087	2.086	2.095	2.068	2.085	2.097	0.1%
1780	3.434	3.496	3.537	3.564	3.628	3.631	3.701	3.697	3.623	3.632	3.644	3.692	3.715	3.728	1.8%
1781	3.050	3.098	3.150	3.195	3.219	3.258	3.278	3.306	3.306	3.327	3.333	3.386	3.406	3.423	2.7%
1782	3.595	3.661	3.716	3.751	3.772	3.815	3.850	3.886	3.811	3.822	3.830	3.873	3.892	3.904	1.8%
1783	2.275	2.325	2.367	2.405	2.432	2.460	2.481	2.486	2.502	2.475	2.478	2.483	2.499	2.498	1.8%
1784	95.53	97.64	99.42	101.02	102.12	103.32	104.21	104.43	105.06	103.97	104.06	104.30	104.97	104.93	1.8%
1785															
1786															
1787	2.802	2.847	2.893	2.936	2.954	2.984	3.007	3.044	3.043	3.052	3.065	3.121	3.140	3.158	1.8%
1788	2.305	2.362	2.406	2.442	2.465	2.490	2.508	2.512	2.526	2.511	2.514	2.526	2.542	2.543	2.5%
1789	96.80	99.22	101.06	102.55	103.53	104.56	105.32	105.51	106.11	105.45	105.60	106.08	106.74	106.79	2.5%
1790															
1791															
1792	2.073	2.103	2.130	2.155	2.170	2.190	2.194	2.211	2.222	2.228	2.230	2.223	2.227	2.228	1.6%
1793	3.434	3.496	3.537	3.564	3.628	3.631	3.701	3.697	3.623	3.632	3.644	3.692	3.715	3.728	1.8%
1794	3.050	3.098	3.150	3.195	3.219	3.258	3.278	3.306	3.306	3.327	3.333	3.386	3.406	3.423	2.7%
1795	3.515	3.581	3.638	3.674	3.723	3.740	3.799	3.815	3.748	3.758	3.767	3.816	3.833	3.845	1.8%
1796	2.326	2.382	2.424	2.461	2.485	2.511	2.529	2.533	2.547	2.526	2.529	2.541	2.557	2.558	1.9%
1797	97.70	100.04	101.82	103.36	104.37	105.46	106.23	106.40	106.99	106.10	106.24	106.74	107.39	107.44	1.9%
1798	**3.18**	**3.24**	**3.28**	**3.31**	**3.36**	**3.38**	**3.43**	**3.44**	**3.39**	**3.40**	**3.41**	**3.46**	**3.48**	**3.49**	**1.9%**
1799															
1800															
1801															
1802															
1803	140.93	146.15	151.13	155.84	160.02	164.61	168.52	173.18	177.51	181.71	185.96	189.49	193.95	198.17	4.6%
1804	128.51	133.33	137.94	142.34	146.09	150.28	153.41	157.69	161.52	165.11	168.69	171.84	175.99	179.87	4.4%
1805															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1806	**Delivered Sector Product Prices**														
1807	**Nominal Dollars per Gallon**														
1808	**Residential**														
1809	Liquefied Petroleum Gases	2.501	2.087	2.263	2.313	2.500	2.587	2.674	2.743	2.836	2.948	3.063	3.172	3.280	3.382
1810	Distillate Fuel Oil	3.400	2.514	2.894	3.073	2.860	2.967	3.076	3.194	3.383	3.576	3.764	3.903	4.057	4.181
1811															
1812	**Commercial**														
1813	Distillate Fuel Oil	2.982	2.205	2.536	2.689	2.575	2.675	2.778	2.892	3.068	3.249	3.427	3.558	3.704	3.826
1814	Residual Fuel Oil	2.344	2.013	2.086	2.283	1.803	1.929	2.054	2.167	2.285	2.412	2.539	2.623	2.750	2.862
1815															
1816	**Industrial 2/**														
1817	Liquefied Petroleum Gases	2.119	1.744	1.888	2.416	1.933	2.012	2.087	2.144	2.222	2.323	2.426	2.523	2.619	2.711
1818	Distillate Fuel Oil	3.079	2.281	2.622	2.777	2.569	2.671	2.778	2.894	3.069	3.251	3.431	3.564	3.712	3.835
1819	Residual Fuel Oil	2.412	1.804	1.860	2.043	2.105	2.191	2.305	2.416	2.538	2.658	2.790	2.892	3.019	3.119
1820															
1821	**Transportation**														
1822	Liquefied Petroleum Gases	2.567	2.161	2.328	2.381	2.571	2.657	2.745	2.814	2.908	3.022	3.138	3.248	3.357	3.460
1823	Ethanol (E85) 3/	3.323	1.945	2.382	2.530	2.326	2.494	2.620	2.734	2.842	2.866	3.056	3.198	3.299	3.368
1824	Ethanol Wholesale Price	2.451	2.028	1.657	1.679	2.567	2.052	2.130	2.788	2.850	2.900	2.992	3.042	3.101	3.129
1825	Motor Gasoline 4/	3.297	2.349	2.707	2.864	2.919	3.126	3.281	3.424	3.557	3.717	3.852	3.958	4.098	4.173
1826	Jet Fuel 5/	3.116	1.700	2.147	2.330	2.526	2.622	2.704	2.799	2.970	3.145	3.317	3.445	3.586	3.708
1827	Diesel Fuel (distillate fuel oil) 6/	3.801	2.441	2.915	3.095	3.017	3.124	3.238	3.363	3.546	3.739	3.932	4.091	4.258	4.348
1828	Residual Fuel Oil	2.161	1.582	1.634	1.794	1.769	1.848	1.953	2.063	2.189	2.294	2.420	2.514	2.632	2.740
1829															
1830	**Electric Power 7/**														
1831	Distillate Fuel Oil	2.688	1.988	2.292	2.441	2.244	2.337	2.431	2.526	2.687	2.862	3.027	3.155	3.284	3.396
1832	Residual Fuel Oil	2.187	1.342	1.726	1.855	1.847	1.931	2.039	2.102	2.224	2.334	2.460	2.553	2.671	2.774
1833															
1834	**Refined Petroleum Product Prices 8/**														
1835	Liquefied Petroleum Gases	1.758	1.477	1.541	1.789	1.808	1.874	1.941	1.994	2.070	2.162	2.256	2.345	2.434	2.516
1836	Motor Gasoline 4/	3.274	2.344	2.703	2.861	2.919	3.126	3.281	3.424	3.557	3.717	3.851	3.958	4.098	4.173
1837	Jet Fuel 5/	3.116	1.700	2.147	2.330	2.526	2.622	2.704	2.799	2.970	3.145	3.317	3.445	3.586	3.708
1838	Distillate Fuel Oil	3.614	2.408	2.847	3.025	2.900	3.025	3.140	3.264	3.448	3.639	3.831	3.986	4.150	4.248
1839	Residual Fuel Oil (dollars per barrel)	92.71	66.20	71.38	78.22	76.95	80.47	84.95	89.15	94.33	98.91	104.21	108.17	113.16	117.62
1840	Average	3.069	2.155	2.491	2.662	2.679	2.832	2.958	3.079	3.220	3.377	3.521	3.636	3.773	3.861
1841															
1842															
1843															
1844															
1845	1/ Weighted average price delivered to U.S. refiners.														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1806															
1807															
1808															
1809	3.481	3.587	3.687	3.785	3.871	3.967	4.046	4.148	4.241	4.327	4.413	4.490	4.583	4.675	3.2%
1810	4.328	4.484	4.639	4.774	4.910	5.033	5.191	5.325	5.377	5.495	5.619	5.832	5.983	6.127	3.5%
1811															
1812															
1813	3.971	4.122	4.268	4.393	4.526	4.639	4.796	4.919	4.948	5.058	5.172	5.358	5.497	5.630	3.7%
1814	3.007	3.190	3.288	3.380	3.465	3.560	3.636	3.718	3.804	3.888	3.987	4.090	4.206	4.321	3.0%
1815															
1816															
1817	2.802	2.894	2.985	3.070	3.142	3.224	3.286	3.372	3.449	3.520	3.592	3.650	3.725	3.799	3.0%
1818	3.988	4.145	4.294	4.418	4.559	4.668	4.834	4.954	4.962	5.072	5.187	5.371	5.510	5.645	3.5%
1819	3.243	3.380	3.502	3.609	3.697	3.793	3.880	3.952	4.040	4.089	4.178	4.331	4.440	4.541	3.6%
1820															
1821															
1822	3.560	3.666	3.768	3.865	3.952	4.050	4.129	4.232	4.326	4.413	4.500	4.577	4.672	4.764	3.1%
1823	3.372	3.512	3.630	3.722	3.861	3.940	4.079	4.152	4.151	4.241	4.342	4.485	4.604	4.716	3.5%
1824	3.232	3.270	3.330	3.364	3.373	3.386	3.433	3.483	3.019	3.075	3.149	3.170	3.262	3.347	1.9%
1825	4.303	4.461	4.594	4.708	4.876	4.968	5.159	5.250	5.241	5.353	5.478	5.660	5.812	5.951	3.6%
1826	3.822	3.953	4.091	4.220	4.326	4.457	4.569	4.695	4.783	4.903	5.010	5.191	5.328	5.464	4.6%
1827	4.505	4.671	4.826	4.954	5.069	5.219	5.366	5.519	5.514	5.634	5.757	5.939	6.090	6.233	3.7%
1828	2.851	2.966	3.075	3.177	3.268	3.366	3.458	3.531	3.619	3.649	3.724	3.807	3.910	3.988	3.6%
1829															
1830															
1831	3.511	3.633	3.758	3.878	3.969	4.082	4.191	4.323	4.403	4.499	4.606	4.785	4.912	5.041	3.6%
1832	2.888	3.014	3.125	3.225	3.313	3.406	3.495	3.568	3.655	3.701	3.779	3.872	3.976	4.059	4.3%
1833															
1834															
1835	2.597	2.683	2.767	2.846	2.917	2.996	3.058	3.140	3.215	3.283	3.352	3.409	3.484	3.556	3.4%
1836	4.303	4.461	4.594	4.708	4.876	4.968	5.158	5.250	5.241	5.353	5.478	5.660	5.812	5.951	3.6%
1837	3.822	3.953	4.091	4.220	4.326	4.457	4.569	4.695	4.783	4.903	5.010	5.191	5.328	5.464	4.6%
1838	4.405	4.570	4.725	4.854	5.004	5.117	5.294	5.418	5.422	5.539	5.662	5.851	5.997	6.138	3.7%
1839	122.44	127.64	132.26	136.53	140.26	144.29	148.05	151.11	154.78	156.38	159.68	163.65	168.02	171.51	3.7%
1840	3.987	4.131	4.261	4.376	4.518	4.622	4.779	4.884	4.907	5.015	5.132	5.302	5.445	5.578	3.7%
1841															
1842															
1843															
1844															
1845															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1846	2/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity,														
1847	or electricity and heat, to the public.														
1848	3/ E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address														
1849	cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of														
1850	74 percent is used for this forecast.														
1851	4/ Sales weighted-average price for all grades. Includes Federal, State, and local taxes.														
1852	5/ Includes only kerosene type.														
1853	6/ Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.														
1854	7/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity,														
1855	or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.														
1856	8/ Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.														
1857	Note: Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.														
1858	Sources: 2008 and 2009 imported low sulfur light crude oil price: Energy														
1859	Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report."														
1860	2008 and 2009 imported crude oil price: EIA,														
1861	Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).														
1862	2008 and 2009 prices for motor gasoline, distillate fuel oil, and														
1863	jet fuel are based on: EIA, Petroleum Marketing Annual 2009, DOE/EIA-0487(2009) (Washington, DC, August 2010).														
1864	2008 and 2009 residential, commercial, industrial, and transportation sector petroleum product														
1865	prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report."														
1866	2008 and 2009 electric power prices based on: EIA, Monthly Energy Review, DOE/EIA-0035(2010/09)														
1867	(Washington, DC, September 2010). 2008 and 2009 E85 prices														
1868	derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2008 and														
1869	2009 wholesale ethanol prices derived from Bloomburg U.S. average rack price.														
1870	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
1871															
1872															
1873															
1874															
1875	**13. Natural Gas Supply, Disposition, and Prices**														
1876	**(trillion cubic feet, unless otherwise noted)**														
1877															
1878	*Supply, Disposition, and Prices*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1879															
1880	**Production**														
1881	Dry Gas Production 1/	20.29	20.96	21.16	20.93	20.73	21.19	21.53	23.29	22.98	23.23	23.71	24.19	24.62	24.87
1882	Supplemental Natural Gas 2/	0.06	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
1883															
1884	**Net Imports**	**2.98**	**2.64**	**2.73**	**2.73**	**2.57**	**2.63**	**2.63**	**2.95**	**2.78**	**2.62**	**2.46**	**2.31**	**2.03**	**1.76**
1885	Pipeline 3/	2.68	2.23	2.32	2.29	2.11	2.14	2.20	2.55	2.37	2.17	1.99	1.79	1.48	1.19
1886	Liquefied Natural Gas	0.30	0.41	0.41	0.44	0.46	0.49	0.43	0.40	0.41	0.46	0.47	0.52	0.55	0.57
1887															
1888	**Total Supply**	**23.33**	**23.66**	**23.95**	**23.72**	**23.36**	**23.89**	**24.22**	**26.31**	**25.82**	**25.92**	**26.24**	**26.56**	**26.71**	**26.69**

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1846															
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1876															
1877															**2009-**
1878	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
1879															
1880															
1881	25.21	25.43	25.47	25.57	25.78	26.00	26.35	26.49	26.87	27.46	28.00	28.69	29.27	30.51	1.5%
1882	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
1883															
1884	**1.56**	**1.42**	**1.37**	**1.31**	**1.23**	**1.14**	**1.03**	**0.95**	**0.94**	**0.88**	**0.79**	**0.65**	**0.51**	**0.27**	**-8.3%**
1885	1.01	0.94	0.95	0.95	0.93	0.90	0.88	0.81	0.80	0.74	0.65	0.51	0.37	0.13	-10.2%
1886	0.55	0.48	0.42	0.37	0.30	0.24	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	-4.1%
1887															
1888	**26.83**	**26.92**	**26.91**	**26.95**	**27.07**	**27.21**	**27.44**	**27.50**	**27.87**	**28.41**	**28.85**	**29.40**	**29.84**	**30.85**	**1.0%**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1889															
1890	**Consumption by Sector**														
1891	Residential	4.87	4.75	4.77	4.76	4.78	4.81	4.83	4.79	4.78	4.76	4.76	4.77	4.78	4.77
1892	Commercial	3.13	3.11	3.10	3.22	3.25	3.30	3.36	3.35	3.33	3.34	3.36	3.39	3.40	3.41
1893	Industrial 4/	6.65	6.15	6.55	6.94	7.19	7.63	7.81	7.77	7.74	7.77	7.78	7.81	7.83	7.81
1894	Natural Gas-to-Liquids Heat and Power 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1895	Natural Gas to Liquids Production 6/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1896	Electric Power 7/	6.67	6.89	7.32	6.87	6.20	6.22	6.30	8.36	7.98	8.06	8.33	8.57	8.66	8.67
1897	Transportation 8/	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
1898	Pipeline Fuel	0.65	0.64	0.65	0.63	0.62	0.63	0.63	0.68	0.66	0.66	0.66	0.67	0.67	0.67
1899	Lease and Plant Fuel 9/	1.22	1.16	1.28	1.26	1.21	1.20	1.18	1.24	1.22	1.22	1.23	1.24	1.25	1.25
1900	**Total**	**23.22**	**22.72**	**23.70**	**23.71**	**23.29**	**23.81**	**24.15**	**26.24**	**25.75**	**25.85**	**26.17**	**26.50**	**26.65**	**26.64**
1901															
1902	**Discrepancy 10/**	**0.11**	**0.94**	**0.26**	**0.01**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.06**	**0.06**	**0.06**
1903															
1904	**Natural Gas Prices**														
1905															
1906	**(2009 dollars per million Btu)**														
1907	Henry Hub Spot Price	8.94	3.95	4.43	4.48	4.34	4.35	4.34	5.47	5.57	5.58	5.60	5.64	5.84	6.00
1908	Average Lower 48 Wellhead Price 11/	7.96	3.62	3.95	3.95	3.85	3.85	3.84	4.84	4.93	4.94	4.96	5.00	5.17	5.31
1909															
1910	**(2009 dollars per thousand cubic feet)**														
1911	Average Lower 48 Wellhead Price 11/	8.18	3.71	4.05	4.06	3.95	3.95	3.94	4.97	5.06	5.07	5.09	5.13	5.31	5.45
1912															
1913	**Delivered Prices**														
1914	Residential	13.99	12.20	11.29	10.53	10.28	10.18	10.06	11.12	11.31	11.45	11.56	11.66	11.96	12.13
1915	Commercial	12.32	9.94	9.12	9.26	8.88	8.60	8.30	9.33	9.49	9.58	9.65	9.72	9.97	10.12
1916	Industrial 4/	9.32	5.39	4.90	4.95	4.84	4.82	4.81	5.88	6.02	6.05	6.07	6.11	6.30	6.45
1917	Electric Power 7/	9.35	4.94	5.16	4.79	4.59	4.51	4.45	5.71	5.78	5.80	5.82	5.88	6.04	6.16
1918	Transportation 12/	17.67	13.05	12.34	12.31	12.14	12.09	12.04	13.03	13.12	13.15	13.16	13.18	13.35	13.46
1919	**Average 13/**	**10.84**	**7.47**	**7.00**	**6.76**	**6.60**	**6.48**	**6.38**	**7.34**	**7.49**	**7.54**	**7.57**	**7.62**	**7.82**	**7.97**
1920	**(nominal dollars per million Btu)**														
1921	Henry Hub Spot Price	8.86	3.95	4.47	4.58	4.49	4.57	4.65	5.98	6.22	6.35	6.52	6.70	7.07	7.39
1922	Average Lower 48 Wellhead Price 11/	7.89	3.62	3.99	4.04	3.98	4.05	4.12	5.30	5.50	5.63	5.77	5.93	6.26	6.54
1923															
1924	**(nominal dollars per thousand cubic feet)**														
1925	Average Lower 48 Wellhead Price 11/	8.10	3.71	4.09	4.15	4.08	4.16	4.22	5.43	5.65	5.77	5.92	6.08	6.42	6.71
1926															
1927	**Delivered Prices**														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1889															
1890															
1891	4.77	4.78	4.79	4.78	4.79	4.79	4.80	4.79	4.79	4.78	4.78	4.75	4.74	4.73	0.0%
1892	3.42	3.43	3.45	3.47	3.49	3.52	3.54	3.58	3.61	3.65	3.68	3.71	3.73	3.77	0.7%
1893	7.75	7.75	7.74	7.75	7.76	7.77	7.83	7.86	7.94	7.98	8.01	8.04	8.03	8.02	1.0%
1894	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1895	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
1896	8.83	8.89	8.86	8.89	8.95	9.06	9.18	9.17	9.41	9.85	10.20	10.69	11.10	11.97	2.1%
1897	0.08	0.08	0.09	0.10	0.10	0.11	0.12	0.12	0.13	0.14	0.14	0.15	0.15	0.16	7.3%
1898	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.68	0.69	0.69	0.70	0.71	0.76	0.7%
1899	1.26	1.26	1.26	1.25	1.25	1.26	1.27	1.27	1.28	1.30	1.31	1.34	1.36	1.42	0.8%
1900	**26.77**	**26.86**	**26.86**	**26.90**	**27.01**	**27.16**	**27.40**	**27.46**	**27.83**	**28.37**	**28.81**	**29.37**	**29.82**	**30.82**	**1.2%**
1901															
1902	**0.06**	**0.05**	**0.05**	**0.05**	**0.06**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.03**	**0.03**	**0.03**	**0.03**	**- -**
1903															
1904															
1905															
1906															
1907	6.14	6.28	6.44	6.57	6.68	6.75	6.83	6.82	6.86	6.98	7.13	7.43	7.70	7.92	2.7%
1908	5.43	5.56	5.70	5.81	5.91	5.97	6.04	6.04	6.07	6.18	6.31	6.58	6.81	7.01	2.6%
1909															
1910															
1911	5.57	5.71	5.85	5.96	6.07	6.13	6.20	6.20	6.23	6.34	6.48	6.75	6.99	7.19	2.6%
1912															
1913															
1914	12.28	12.45	12.61	12.77	12.93	13.05	13.17	13.21	13.31	13.48	13.66	14.02	14.30	14.53	0.7%
1915	10.25	10.39	10.53	10.65	10.78	10.88	10.98	10.98	11.04	11.17	11.32	11.61	11.86	12.07	0.7%
1916	6.57	6.69	6.82	6.92	7.01	7.08	7.15	7.15	7.17	7.28	7.44	7.72	7.99	8.22	1.6%
1917	6.29	6.41	6.50	6.58	6.68	6.76	6.84	6.85	6.89	7.04	7.20	7.49	7.79	8.09	1.9%
1918	13.54	13.63	13.71	13.79	13.86	13.91	13.96	13.93	13.94	14.02	14.12	14.36	14.58	14.76	0.5%
1919	**8.09**	**8.22**	**8.35**	**8.46**	**8.57**	**8.65**	**8.74**	**8.74**	**8.78**	**8.88**	**9.02**	**9.29**	**9.54**	**9.75**	**1.0%**
1920															
1921	7.69	8.02	8.36	8.67	8.97	9.23	9.51	9.69	9.92	10.29	10.72	11.39	12.04	12.64	4.6%
1922	6.81	7.10	7.40	7.68	7.95	8.17	8.42	8.58	8.78	9.11	9.49	10.08	10.66	11.19	4.4%
1923															
1924															
1925	6.99	7.28	7.60	7.88	8.15	8.39	8.64	8.80	9.01	9.35	9.74	10.34	10.93	11.48	4.4%
1926															
1927															

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Residential	13.86	12.20	11.39	10.76	10.64	10.71	10.77	12.16	12.62	13.05	13.45	13.83	14.47	14.95
Commercial	12.20	9.94	9.20	9.47	9.18	9.05	8.90	10.21	10.59	10.91	11.22	11.53	12.07	12.47
Industrial 4/	9.24	5.39	4.95	5.06	5.00	5.07	5.15	6.43	6.71	6.89	7.07	7.25	7.62	7.95
Electric Power 7/	9.26	4.94	5.20	4.89	4.75	4.75	4.77	6.24	6.45	6.61	6.78	6.97	7.31	7.59
Transportation 12/	17.50	13.05	12.45	12.58	12.56	12.72	12.90	14.25	14.64	14.98	15.31	15.64	16.16	16.58
Average 13/	10.74	7.47	7.06	6.91	6.83	6.82	6.83	8.02	8.36	8.59	8.81	9.04	9.47	9.82

1/ Marketed production (wet) minus extraction losses.

2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.

4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.

6/ Includes any natural gas converted into liquid fuel.

7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

8/ Compressed natural gas used as vehicle fuel.

9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.

10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2008 and 2009 values include net storage injections.

11/ Represents lower 48 onshore and offshore supplies.

12/ Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.

13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010).
2009 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2010/07) (Washington, DC, July 2010).
Other 2008 and 2009 consumption based on: EIA, Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).
2008 wellhead price: Minerals Management Service and EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010).
2008 residential and commercial delivered prices: EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010).

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
1928	15.40	15.88	16.38	16.87	17.37	17.86	18.36	18.76	19.25	19.87	20.53	21.49	22.37	23.19	2.5%
1929	12.84	13.25	13.68	14.07	14.49	14.88	15.30	15.59	15.96	16.46	17.01	17.81	18.56	19.26	2.6%
1930	8.24	8.53	8.86	9.14	9.43	9.69	9.96	10.15	10.37	10.74	11.18	11.84	12.50	13.13	3.5%
1931	7.88	8.17	8.44	8.70	8.98	9.25	9.54	9.72	9.97	10.37	10.81	11.48	12.19	12.92	3.8%
1932	16.97	17.39	17.81	18.21	18.62	19.03	19.46	19.79	20.16	20.66	21.23	22.01	22.80	23.57	2.3%
1933	10.14	10.49	10.85	11.18	11.52	11.84	12.18	12.42	12.70	13.09	13.56	14.24	14.93	15.56	2.9%
1934															
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1972	2009 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130														
1973	(2010/07) (Washington, DC, July 2010). 2008 and 2009 electric power prices: EIA,														
1974	Electric Power Monthly, DOE/EIA-0226, April 2009 and April 2010, Table 4.13.B. 2008 and 2009														
1975	industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey and industrial														
1976	and wellhead prices from the Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010)														
1977	and the Natural Gas Monthly, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 transportation sector														
1978	delivered prices are based on: EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010)														
1979	and estimated state taxes, federal taxes, and dispensing costs or charges.														
1980	2009 transportation sector delivered prices are model results.														
1981	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
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1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
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2020															
2021															
2022															
2023															
2024															
2025	**14. Oil and Gas Supply**														
2026															
2027															
2028	*Production and Supply*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2029															
2030	**Crude Oil**														
2031															
2032	**Lower 48 Average Wellhead Price 1/**														
2033	**(2009 dollars per barrel)**	**96.13**	**89.96**	**78.62**	**84.02**	**86.25**	**88.66**	**92.01**	**94.83**	**97.98**	**100.83**	**103.57**	**104.99**	**107.28**	**108.53**
2034															
2035	**Production (million barrels per day) 2/**														
2036	United States Total	4.96	5.36	5.51	5.46	5.38	5.58	5.75	5.82	5.96	6.08	6.11	6.12	6.09	6.07
2037	Lower 48 Onshore	3.01	3.00	3.11	3.32	3.38	3.43	3.47	3.52	3.56	3.62	3.63	3.68	3.73	3.76
2038	Lower 48 Offshore	1.27	1.71	1.79	1.55	1.45	1.62	1.77	1.81	1.93	2.01	2.05	2.04	1.94	1.87
2039	Alaska	0.69	0.65	0.61	0.59	0.55	0.53	0.52	0.49	0.47	0.45	0.42	0.40	0.42	0.45
2040															
2041	**Lower 48 End of Year Reserves 2/**														
2042	**(billion barrels)**	**17.05**	**17.88**	**17.63**	**17.95**	**18.02**	**18.67**	**19.31**	**19.69**	**20.25**	**20.73**	**21.14**	**21.50**	**21.62**	**21.74**
2043															
2044	**Natural Gas**														
2045															
2046	**Prices (2009 dollars per million Btu)**														
2047	Henry Hub Spot Price	8.94	3.95	4.43	4.48	4.34	4.35	4.34	5.47	5.57	5.58	5.60	5.64	5.84	6.00
2048	Lower 48 Average Wellhead Price 1/	7.96	3.62	3.95	3.95	3.85	3.85	3.84	4.84	4.93	4.94	4.96	5.00	5.17	5.31
2049															
2050	**Prices (2009 dollars per thousand cubic feet)**														
2051	Lower 48 Average Wellhead Price 1/	8.18	3.71	4.05	4.06	3.95	3.95	3.94	4.97	5.06	5.07	5.09	5.13	5.31	5.45

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2013															
2014															
2015															
2016															
2017															
2018															
2019															
2020															
2021															
2022															
2023															
2024															
2025															
2026															
2027															**2009-**
2028	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2029															
2030															
2031															
2032															
2033	**110.38**	**112.38**	**114.13**	**115.73**	**116.71**	**118.04**	**117.89**	**118.09**	**118.06**	**117.91**	**118.11**	**116.52**	**116.90**	**116.95**	**1.0%**
2034															
2035															
2036	6.08	6.00	5.89	5.84	5.79	5.84	5.85	5.89	5.92	6.00	6.14	6.25	6.21	6.17	0.5%
2037	3.80	3.84	3.84	3.83	3.81	3.80	3.78	3.81	3.84	3.83	3.83	3.85	3.86	3.88	1.0%
2038	1.82	1.72	1.63	1.59	1.61	1.70	1.75	1.79	1.80	1.86	1.93	1.98	1.94	1.90	0.4%
2039	0.46	0.44	0.42	0.41	0.37	0.34	0.32	0.29	0.27	0.31	0.37	0.42	0.40	0.39	-1.9%
2040															
2041															
2042	**21.89**	**21.88**	**21.80**	**21.85**	**21.99**	**22.31**	**22.56**	**22.77**	**23.17**	**23.36**	**23.48**	**23.71**	**23.63**	**23.72**	**1.1%**
2043															
2044															
2045															
2046															
2047	6.14	6.28	6.44	6.57	6.68	6.75	6.83	6.82	6.86	6.98	7.13	7.43	7.70	7.92	2.7%
2048	5.43	5.56	5.70	5.81	5.91	5.97	6.04	6.04	6.07	6.18	6.31	6.58	6.81	7.01	2.6%
2049															
2050															
2051	5.57	5.71	5.85	5.96	6.07	6.13	6.20	6.20	6.23	6.34	6.48	6.75	6.99	7.19	2.6%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2052															
2053	**Dry Production (trillion cubic feet) 3/**														
2054	United States Total	20.29	20.96	21.16	20.93	20.73	21.19	21.53	23.29	22.98	23.23	23.71	24.19	24.62	24.87
2055	Lower 48 Onshore	17.22	17.88	18.43	18.39	18.39	19.01	19.24	20.76	20.45	20.57	20.84	21.06	21.41	21.73
2056	Associated-Dissolved 4/	1.42	1.40	1.57	1.54	1.57	1.57	1.53	1.49	1.44	1.42	1.41	1.41	1.43	1.41
2057	Non-Associated	15.81	16.48	16.86	16.85	16.81	17.44	17.71	19.28	19.01	19.15	19.43	19.64	19.98	20.32
2058	Tight Gas	6.75	6.59	6.17	5.94	5.71	5.77	5.76	6.18	5.85	5.80	5.80	5.77	5.82	5.82
2059	Shale Gas	2.23	3.28	4.74	5.14	5.56	6.16	6.53	7.36	7.82	8.17	8.50	8.83	9.21	9.64
2060	Coalbed Methane	1.87	1.80	1.70	1.71	1.64	1.64	1.63	1.75	1.73	1.71	1.75	1.76	1.79	1.78
2061	Other	4.95	4.80	4.24	4.05	3.89	3.88	3.79	3.99	3.62	3.47	3.38	3.28	3.16	3.09
2062	Lower 48 Offshore	2.69	2.70	2.38	2.19	2.00	1.88	2.00	2.24	2.25	2.39	2.60	2.87	2.96	2.88
2063	Associated-Dissolved 4/	0.62	0.64	0.58	0.54	0.52	0.48	0.57	0.64	0.67	0.74	0.80	0.85	0.87	0.84
2064	Non-Associated	2.07	2.05	1.79	1.66	1.48	1.40	1.43	1.60	1.58	1.65	1.81	2.02	2.09	2.04
2065	Alaska	0.37	0.37	0.35	0.35	0.35	0.30	0.29	0.28	0.28	0.27	0.27	0.26	0.26	0.26
2066															
2067	**Lower 48 End of Year Dry Reserves (tcf)**	**236.96**	**261.37**	**263.88**	**266.29**	**269.39**	**272.89**	**276.99**	**278.47**	**281.63**	**285.61**	**289.15**	**292.56**	**294.47**	**296.44**
2068															
2069	**Supplemental Gas Supplies (tcf) 5/**	**0.06**	**0.06**	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
2070															
2071	**Total Lower 48 Wells Drilled (thousands**	**56.20**	**35.06**	**33.13**	**30.61**	**31.44**	**33.43**	**34.05**	**42.20**	**42.48**	**43.55**	**44.14**	**44.88**	**45.88**	**46.97**
2072															
2073															
2074															
2075															

2076 1/ Represents lower 48 onshore and offshore supplies.
2077 2/ Includes lease condensate.
2078 3/ Marketed production (wet) minus extraction losses.
2079 4/ Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
2080 5/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu
2081 stabilization, and manufactured gas commingled and distributed with natural gas.
2082 Tcf = Trillion cubic feet.
2083 Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009
2084 are model results and may differ slightly from official EIA data reports.
2085 Sources: 2008 and 2009 crude oil lower 48 average wellhead price: U.S. Energy Information
2086 Administration (EIA), Petroleum Marketing Annual 2009, DOE/EIA-0487(2009) (Washington, DC, August 2010).
2087 2008 and 2009 lower 48 onshore, lower 48 offshore, and Alaska crude oil production:
2088 EIA, Petroleum Supply Annual 2009, DOE/EIA-0340(2009)/1 (Washington, DC, July 2010).
2089 2008 U.S. crude oil and natural gas reserves: EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids
2090 Reserves, DOE/EIA-0216(2009) (Washington, DC, October 2010). 2008
2091 Alaska and total natural gas production, and supplemental gas supplies: EIA, Natural Gas Annual
2092 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2008 natural gas lower 48 average wellhead price: Minerals
2093 Management Service and EIA, Natural Gas Annual 2008, DOE/EIA-0131(2008) (Washington, DC, March 2010).

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2052															
2053															
2054	25.21	25.43	25.47	25.57	25.78	26.00	26.35	26.49	26.87	27.46	28.00	28.69	29.27	30.51	1.5%
2055	22.13	22.42	22.64	22.87	23.10	23.27	23.43	23.36	23.56	24.03	24.54	25.25	25.93	26.48	1.5%
2056	1.38	1.38	1.36	1.35	1.31	1.27	1.23	1.21	1.20	1.18	1.17	1.07	1.05	1.03	-1.2%
2057	20.75	21.04	21.28	21.52	21.79	22.00	22.21	22.15	22.36	22.85	23.37	24.18	24.88	25.46	1.7%
2058	5.86	5.87	5.89	5.89	5.91	5.91	5.91	5.83	5.81	5.85	5.91	6.02	6.10	6.05	-0.3%
2059	10.07	10.47	10.76	11.07	11.40	11.68	11.96	12.10	12.41	12.88	13.38	14.07	14.69	15.37	6.1%
2060	1.78	1.78	1.78	1.78	1.78	1.77	1.76	1.73	1.72	1.72	1.73	1.76	1.80	1.81	0.0%
2061	3.04	2.93	2.85	2.77	2.70	2.63	2.58	2.48	2.43	2.39	2.35	2.33	2.28	2.23	-2.9%
2062	2.82	2.76	2.59	2.47	2.44	2.50	2.68	2.90	3.08	3.21	3.24	3.22	3.12	3.03	0.4%
2063	0.81	0.80	0.74	0.69	0.67	0.66	0.70	0.73	0.76	0.77	0.78	0.80	0.82	0.79	0.8%
2064	2.01	1.96	1.85	1.77	1.77	1.83	1.98	2.17	2.32	2.44	2.46	2.42	2.31	2.23	0.3%
2065	0.25	0.25	0.25	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.21	1.00	3.8%
2066															
2067	**298.58**	**300.07**	**300.92**	**302.35**	**304.05**	**306.31**	**308.56**	**311.36**	**314.14**	**316.25**	**318.00**	**319.22**	**320.01**	**321.63**	**0.8%**
2068															
2069	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.0%**
2070															
2071	**49.45**	**50.05**	**50.46**	**51.08**	**52.05**	**52.62**	**53.41**	**53.72**	**54.61**	**57.03**	**58.72**	**59.54**	**61.65**	**61.90**	**2.2%**
2072															
2073															
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2094	2009 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies:														
2095	EIA, Natural Gas Monthly, DOE/EIA-0130(2010/07) (Washington, DC, July 2010).														
2096	Other 2008 and 2009 values: EIA, Office of Integrated Analysis and Forecasting.														
2097	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
2098															
2099															
2100															
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2131															
2132															
2133															

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2094															
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2131															
2132															
2133															

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

15. Coal Supply, Disposition, and Prices

(million short tons, unless otherwise noted)

Supply, Disposition, and Prices	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Production 1/														
Appalachia	391	343	356	335	302	289	279	245	241	223	236	230	234	230
Interior	147	147	149	150	166	166	167	139	141	135	141	136	140	139
West	634	585	604	588	614	617	606	505	537	538	531	528	536	523
East of the Mississippi	493	450	466	444	425	413	403	355	354	331	349	337	346	341
West of the Mississippi	678	625	642	629	657	659	650	533	565	566	559	557	564	551
Total	**1172**	**1075**	**1109**	**1073**	**1083**	**1072**	**1053**	**889**	**919**	**896**	**908**	**894**	**910**	**892**
Waste Coal Supplied 2/	**14**	**12**	**14**	**13**	**12**	**15**	**16**	**8**	**12**	**7**	**8**	**7**	**8**	**7**
Net Imports														
Imports 3/	32	21	17	24	30	32	32	30	30	29	11	17	18	24
Exports	82	59	77	74	74	74	71	70	71	62	72	74	76	73
Total	**-49**	**-38**	**-59**	**-50**	**-44**	**-42**	**-40**	**-40**	**-41**	**-33**	**-61**	**-56**	**-59**	**-49**
Total Supply 4/	**1136**	**1049**	**1063**	**1036**	**1051**	**1046**	**1029**	**857**	**890**	**871**	**854**	**845**	**860**	**850**

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2134															
2135															
2136															
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2147															
2148															
2149															
2150															
2151															
2152															**2009-**
2153	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2154															
2155															
2156	238	235	234	230	226	213	205	198	189	178	168	164	168	167	-2.7%
2157	131	132	131	129	129	129	123	125	119	113	109	112	118	113	-1.0%
2158	528	517	518	512	510	502	493	479	466	455	447	456	480	484	-0.7%
2159															
2160	341	340	337	331	324	315	300	296	283	267	252	252	256	253	-2.2%
2161	556	545	546	541	540	530	521	506	491	479	471	480	509	511	-0.8%
2162	**896**	**884**	**883**	**871**	**864**	**845**	**821**	**802**	**775**	**746**	**724**	**732**	**765**	**764**	**-1.3%**
2163															
2164	**8**	**8**	**7**	**7**	**7**	**7**	**7**	**7**	**6**	**4**	**3**	**3**	**4**	**3**	**-4.9%**
2165															
2166															
2167	21	25	24	23	23	20	19	18	16	13	14	13	11	11	-2.5%
2168	74	73	73	73	72	72	67	66	65	66	64	69	58	54	-0.3%
2169	**-53**	**-48**	**-50**	**-50**	**-50**	**-52**	**-48**	**-49**	**-50**	**-53**	**-51**	**-56**	**-47**	**-44**	**0.5%**
2170															
2171	**852**	**845**	**840**	**828**	**821**	**800**	**780**	**760**	**731**	**697**	**677**	**679**	**722**	**724**	**-1.4%**
2172															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2173	**Consumption by Sector**														
2174	Residential and Commercial	4	3	3	3	3	3	3	3	3	3	3	3	3	3
2175	Coke Plants	22	15	21	22	22	23	22	22	21	21	21	21	21	21
2176	Other Industrial 5/	54	45	48	48	48	49	49	48	48	48	48	48	48	48
2177	Coal-to-Liquids Heat and Power	0	0	0	0	0	0	0	5	6	6	6	6	7	8
2178	Coal to Liquids Production	0	0	0	0	0	0	0	5	6	6	6	6	6	7
2179	Electric Power 6/	1041	937	992	964	978	971	955	772	806	786	770	761	775	763
2180	**Total**	**1121**	**1000**	**1063**	**1036**	**1051**	**1045**	**1029**	**856**	**890**	**871**	**854**	**845**	**861**	**850**
2181															
2182	**Discrepancy and Stock Change 7/**	**16**	**49**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**-1**	**0**
2183															
2184	**Average Minemouth Price 8/**														
2185	(2009 dollars per short ton)	31.54	33.26	36.78	35.57	34.05	33.62	33.10	33.17	32.25	31.11	32.43	32.38	32.68	32.91
2186	(2009 dollars per million Btu)	1.56	1.67	1.80	1.75	1.69	1.68	1.65	1.64	1.61	1.56	1.62	1.62	1.63	1.64
2187															
2188	**Delivered Prices**														
2189	**(2009 dollars per short ton) 9/**														
2190	Coke Plants	119.20	143.01	161.49	159.93	159.12	160.97	157.80	157.05	152.93	159.87	161.43	164.73	166.55	167.70
2191	Other Industrial 5/	64.03	64.87	65.18	64.25	63.49	63.50	62.49	61.05	58.76	61.09	60.47	60.26	59.95	60.21
2192	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	30.42	30.00	30.49	30.76	30.87	31.04	31.40
2193	**Electric Power**														
2194	(2009 dollars per short ton)	41.07	43.48	44.98	44.24	42.93	41.94	41.34	40.80	39.32	39.40	39.09	38.78	38.82	39.10
2195	(2009 dollars per million Btu)	2.07	2.20	2.27	2.24	2.20	2.16	2.13	2.08	2.02	2.03	2.02	2.01	2.01	2.02
2196	**Average**	**43.77**	**46.03**	**48.16**	**47.57**	**46.26**	**45.52**	**44.86**	**44.80**	**42.99**	**43.45**	**43.26**	**43.07**	**43.05**	**43.40**
2197	Exports 10/	98.60	101.44	129.94	127.07	126.31	127.56	125.28	122.64	119.89	121.80	126.55	130.56	132.54	136.31
2198															
2199															
2200	**Average Minemouth Price 8/**														
2201	(nominal dollars per short ton)	31.25	33.26	37.11	36.36	35.22	35.38	35.45	36.27	35.99	35.45	37.74	38.42	39.55	40.56
2202	(nominal dollars per million Btu)	1.55	1.67	1.82	1.79	1.75	1.76	1.77	1.80	1.79	1.78	1.88	1.92	1.97	2.02
2203															
2204	**Delivered Prices**														
2205	**(nominal dollars per short ton) 9/**														
2206	Coke Plants	118.09	143.01	162.91	163.47	164.59	169.39	169.04	171.74	170.65	182.19	187.85	195.47	201.54	206.65
2207	Other Industrial 5/	63.44	64.87	65.76	65.67	65.66	66.82	66.94	66.76	65.57	69.62	70.36	71.51	72.54	74.20
2208	Coal to Liquids	- -	- -	- -	- -	- -	- -	- -	33.26	33.47	34.74	35.79	36.63	37.56	38.69
2209	**Electric Power**														
2210	(nominal dollars per short ton)	40.69	43.48	45.37	45.22	44.40	44.13	44.28	44.62	43.88	44.90	45.49	46.01	46.98	48.19
2211	(nominal dollars per million Btu)	2.05	2.20	2.29	2.29	2.27	2.27	2.28	2.28	2.26	2.31	2.35	2.38	2.43	2.49

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2173															
2174	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-0.2%
2175	21	21	21	20	20	20	19	19	19	18	18	18	17	17	0.4%
2176	48	48	48	48	48	47	47	47	47	47	47	46	46	46	0.1%
2177	10	15	18	22	25	29	33	37	41	46	51	56	61	66	- -
2178	9	14	17	20	23	27	31	34	38	43	48	53	57	62	- -
2179	763	743	732	716	699	675	647	619	582	542	510	502	538	528	-2.2%
2180	**853**	**845**	**839**	**829**	**818**	**801**	**779**	**760**	**731**	**699**	**676**	**679**	**723**	**722**	**-1.2%**
2181															
2182	**-1**	**0**	**1**	**-1**	**3**	**0**	**1**	**0**	**0**	**-2**	**1**	**1**	**-1**	**2**	- -
2183															
2184															
2185	32.97	33.18	33.18	33.27	33.24	33.06	32.95	33.00	32.93	32.59	31.92	31.39	30.53	30.13	-0.4%
2186	1.64	1.65	1.65	1.66	1.66	1.65	1.65	1.65	1.65	1.64	1.61	1.59	1.55	1.54	-0.3%
2187															
2188															
2189															
2190	167.08	168.96	168.59	170.96	170.98	171.68	171.91	172.41	172.34	173.38	173.72	173.43	173.02	172.10	0.7%
2191	59.70	60.17	59.66	60.14	60.06	59.63	59.62	59.12	58.43	57.87	57.60	57.40	58.59	59.59	-0.3%
2192	29.56	29.64	28.61	28.34	27.96	28.18	28.58	28.78	28.20	27.47	27.17	27.15	27.90	29.03	- -
2193															
2194	39.18	39.42	39.49	39.70	39.69	39.29	39.14	38.86	38.28	37.58	36.88	36.73	37.49	37.91	-0.5%
2195	2.02	2.03	2.03	2.04	2.04	2.02	2.02	2.00	1.97	1.94	1.91	1.90	1.94	1.96	-0.4%
2196	**43.32**	**43.48**	**43.35**	**43.53**	**43.40**	**42.98**	**42.83**	**42.54**	**41.94**	**41.26**	**40.58**	**40.21**	**40.57**	**40.91**	**-0.5%**
2197	135.44	137.35	136.37	138.51	138.23	138.57	142.78	142.62	142.13	142.60	141.15	132.17	133.83	127.65	0.9%
2198															
2199															
2200															
2201	41.32	42.33	43.09	43.95	44.68	45.23	45.92	46.87	47.63	48.03	47.98	48.12	47.76	48.10	1.4%
2202	2.06	2.11	2.15	2.19	2.23	2.26	2.30	2.35	2.39	2.42	2.43	2.44	2.43	2.45	1.5%
2203															
2204															
2205															
2206	209.39	215.57	218.98	225.82	229.78	234.89	239.58	244.85	249.31	255.54	261.11	265.89	270.69	274.74	2.5%
2207	74.82	76.77	77.49	79.44	80.71	81.58	83.09	83.96	84.53	85.30	86.57	88.01	91.67	95.13	1.5%
2208	37.05	37.82	37.16	37.43	37.57	38.56	39.84	40.88	40.80	40.49	40.83	41.63	43.64	46.35	- -
2209															
2210	49.10	50.30	51.29	52.44	53.34	53.75	54.55	55.19	55.38	55.39	55.43	56.31	58.66	60.51	1.3%
2211	2.53	2.59	2.63	2.69	2.74	2.77	2.81	2.84	2.85	2.86	2.87	2.92	3.04	3.12	1.4%

cesbingbk.d100611a	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Average	43.37	46.03	48.59	48.63	47.85	47.90	48.05	48.99	47.97	49.52	50.34	51.10	52.09	53.48
Exports 10/	97.68	101.44	131.08	129.89	130.64	134.23	134.20	134.12	133.78	138.80	147.26	154.92	160.39	167.97

1/ Includes anthracite, bituminous coal, subbituminous coal, and lignite.
2/ Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
3/ Excludes imports to Puerto Rico and the U.S. Virgin Islands.
4/ Production plus waste coal supplied plus net imports.
5/ Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
6/ Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
7/ Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
8/ Includes reported prices for both open market and captive mines.
9/ Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
10/ F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 data based on: U.S. Energy Information Administration (EIA), Annual Coal Report 2009, DOE/EIA-0584(2009) (Washington, DC, October 2010); EIA, Quarterly Coal Report, October-December 2009, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010); and EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a. Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

16. Renewable Energy Generating Capacity and Generation

(gigawatts, unless otherwise noted)

Electricity and Nonelectric	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2212	54.29	55.47	56.31	57.51	58.32	58.80	59.68	60.41	60.67	60.81	60.99	61.65	63.46	65.31	1.4%
2213	169.74	175.25	177.12	182.96	185.76	189.59	198.98	202.55	205.61	210.18	212.15	202.64	209.38	203.77	2.7%
2214															
2215															
2216															
2217															
2218															
2219															
2220															
2221															
2222															
2223															
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2238															
2239															
2240															
2241															
2242															
2243															
2244															
2245															
2246															
2247															
2248															
2249															
2250															
2251															
2252															**2009-**
2253	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2254															
2255	**Electric Power Sector 1/**														
2256	**Net Summer Capacity**														
2257	Conventional Hydropower	76.87	76.87	76.87	76.83	76.82	76.82	78.16	78.63	78.88	78.88	78.88	78.88	78.88	78.88
2258	Geothermal 2/	2.42	2.42	2.41	2.41	2.68	2.91	2.91	2.91	2.91	2.91	2.91	2.91	3.09	3.09
2259	Municipal Waste 3/	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37
2260	Wood and Other Biomass 4/	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19
2261	Solar Thermal	0.53	0.61	0.61	0.74	1.00	1.25	1.25	1.26	1.26	1.27	1.27	1.27	1.28	1.28
2262	Solar Photovoltaic 5/	0.05	0.07	0.08	0.10	0.11	0.13	0.15	0.16	0.18	0.19	0.21	0.22	0.24	0.26
2263	Wind	24.89	31.45	37.49	42.82	59.61	62.59	62.59	62.59	62.65	63.49	63.49	63.49	63.49	63.49
2264	Offshore Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
2265	**Total**	**110.31**	**116.98**	**123.02**	**128.45**	**145.78**	**149.26**	**150.82**	**151.30**	**151.63**	**152.49**	**152.51**	**152.53**	**152.73**	**152.76**
2266															
2267	**Generation (billion kilowatthours)**														
2268	Conventional Hydropower	253.09	270.20	240.02	258.36	266.94	274.29	287.98	297.94	306.58	306.60	306.61	306.63	279.27	306.64
2269	Geothermal 2/	14.95	15.21	16.91	16.91	18.84	20.66	20.86	20.86	20.86	20.86	20.86	20.87	22.36	22.36
2270	Biogenic Municipal Waste 6/	15.68	16.39	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80
2271	Wood and Other Biomass	10.46	10.39	9.17	8.36	13.18	18.58	24.67	59.41	92.45	153.23	172.21	182.32	190.87	197.37
2272	Dedicated Plants	8.58	8.73	7.37	6.62	5.61	5.29	4.97	12.17	11.97	11.36	11.21	11.58	12.37	11.61
2273	Cofiring	1.88	1.66	1.81	1.74	7.57	13.29	19.69	47.24	80.48	141.87	161.00	170.74	178.50	185.76
2274	Solar Thermal	0.83	0.76	1.13	1.22	1.59	2.30	2.48	2.49	2.49	2.50	2.51	2.51	2.52	2.53
2275	Solar Photovoltaic 5/	0.04	0.04	0.20	0.22	0.27	0.31	0.35	0.39	0.42	0.46	0.50	0.54	0.58	0.63
2276	Wind	55.42	70.82	91.25	109.94	176.90	186.06	186.06	186.06	186.23	188.63	188.65	188.65	188.65	188.65
2277	Offshore Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.75	0.75	0.75	0.75	0.75	0.75	0.75
2278	**Total**	**350.47**	**383.82**	**373.48**	**409.80**	**492.51**	**517.00**	**537.43**	**582.69**	**624.59**	**687.83**	**706.89**	**717.06**	**699.80**	**733.73**
2279															
2280	**End-Use Generators 7/**														
2281	**Net Summer Capacity**														
2282	Conventional Hydropower 8/	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
2283	Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2284	Municipal Waste 9/	0.29	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
2285	Biomass	4.86	4.86	5.37	5.80	6.28	6.75	6.81	7.13	7.29	7.73	8.12	8.61	9.37	10.32
2286	Solar Photovoltaic 5/	0.77	1.50	2.26	3.48	4.62	5.54	6.49	7.67	8.95	8.98	9.02	9.06	9.12	9.19
2287	Wind	0.08	0.18	0.38	0.70	0.90	1.07	1.22	1.44	1.67	1.67	1.67	1.67	1.67	1.68
2288	**Total**	**6.70**	**7.55**	**9.02**	**10.98**	**12.81**	**14.38**	**15.54**	**17.26**	**18.93**	**19.40**	**19.82**	**20.36**	**21.17**	**22.20**
2289															
2290	**Generation (billion kilowatthours)**														
2291	Conventional Hydropower 8/	3.33	3.34	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
2292	Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2254															
2255															
2256															
2257	78.94	81.78	81.80	81.80	81.80	81.80	81.80	81.82	81.82	81.82	81.82	81.82	81.82	81.82	0.2%
2258	3.09	3.31	3.55	3.83	4.12	4.44	4.82	5.25	5.61	5.90	6.06	6.16	6.30	6.41	3.8%
2259	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	0.0%
2260	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	0.0%
2261	1.29	1.29	1.30	1.30	1.30	1.31	1.31	1.32	1.32	1.33	1.33	1.34	1.35	1.35	3.1%
2262	0.28	0.29	0.31	0.33	0.35	0.36	0.38	0.40	0.42	0.43	0.44	0.45	0.46	1.39	12.0%
2263	63.49	66.92	70.86	75.40	80.61	86.61	93.51	101.44	110.56	112.92	112.92	112.92	112.92	113.96	5.1%
2264	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	- -
2265	**152.84**	**159.34**	**163.58**	**168.42**	**173.94**	**180.29**	**187.58**	**195.98**	**205.49**	**208.14**	**208.32**	**208.44**	**208.59**	**210.69**	**2.3%**
2266															
2267															
2268	306.90	318.00	318.12	318.13	318.14	318.15	318.16	318.23	318.24	318.25	318.26	317.58	317.59	308.90	0.5%
2269	22.36	24.07	26.04	28.31	30.62	33.28	36.34	39.86	42.77	45.09	46.43	47.25	48.38	49.33	4.6%
2270	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	-0.4%
2271	199.29	198.13	198.96	199.76	198.03	197.70	194.18	189.36	180.98	169.49	154.56	157.02	169.82	168.81	11.3%
2272	11.95	11.68	11.96	12.16	12.31	12.30	12.46	12.21	12.55	12.74	12.71	12.74	12.95	12.95	1.5%
2273	187.34	186.45	187.00	187.60	185.73	185.40	181.72	177.15	168.43	156.75	141.85	144.29	156.87	155.86	19.1%
2274	2.54	2.55	2.55	2.56	2.57	2.58	2.59	2.59	2.60	2.61	2.62	2.64	2.65	2.66	4.9%
2275	0.67	0.72	0.76	0.81	0.85	0.90	0.94	0.98	1.03	1.06	1.09	1.11	1.14	3.72	18.6%
2276	188.65	200.72	214.37	230.07	247.49	265.22	288.17	313.12	337.32	344.19	344.21	344.21	344.21	347.89	6.3%
2277	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	- -
2278	**735.97**	**759.73**	**776.35**	**795.19**	**813.25**	**833.38**	**855.93**	**879.69**	**898.49**	**896.23**	**882.72**	**885.37**	**899.33**	**896.85**	**3.3%**
2279															
2280															
2281															
2282	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.0%
2283	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2284	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.0%
2285	11.44	12.61	13.77	14.97	15.92	16.91	17.41	17.52	17.48	17.59	17.70	17.81	17.92	18.03	5.2%
2286	9.26	9.34	9.44	9.55	9.68	9.83	10.00	10.19	10.39	10.55	10.72	10.89	11.09	11.32	8.1%
2287	1.68	1.68	1.69	1.70	1.71	1.73	1.74	1.76	1.77	1.79	1.81	1.84	1.87	1.91	9.4%
2288	**23.39**	**24.65**	**25.92**	**27.24**	**28.32**	**29.47**	**30.17**	**30.47**	**30.66**	**30.95**	**31.24**	**31.55**	**31.89**	**32.27**	**5.7%**
2289															
2290															
2291	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	0.2%
2292	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2293	Municipal Waste 9/	1.94	1.96	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
2294	Biomass	27.88	27.88	30.88	33.35	36.24	39.12	39.62	41.80	43.09	46.13	49.14	53.08	59.08	66.71
2295	Solar Photovoltaic 5/	1.22	2.34	3.48	5.35	7.08	8.52	10.03	11.91	13.95	14.00	14.06	14.14	14.24	14.34
2296	Wind	0.10	0.24	0.50	0.90	1.18	1.42	1.64	1.96	2.30	2.30	2.30	2.30	2.30	2.30
2297	**Total**	**34.47**	**35.76**	**40.91**	**45.65**	**50.55**	**55.11**	**57.34**	**61.72**	**65.38**	**68.48**	**71.55**	**75.57**	**81.67**	**89.41**
2298															
2299															
2300	**All Sectors**														
2301	**Net Summer Capacity**														
2302	Conventional Hydropower	77.58	77.57	77.57	77.53	77.53	77.53	78.87	79.33	79.58	79.58	79.58	79.58	79.58	79.58
2303	Geothermal	2.42	2.42	2.41	2.41	2.68	2.91	2.91	2.91	2.91	2.91	2.91	2.91	3.09	3.09
2304	Municipal Waste	3.66	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67
2305	Wood and Other Biomass 4/	7.04	7.04	7.56	7.98	8.47	8.94	9.00	9.32	9.48	9.92	10.31	10.79	11.55	12.51
2306	Solar 5/	1.35	2.18	2.95	4.32	5.73	6.93	7.89	9.09	10.39	10.44	10.49	10.56	10.64	10.73
2307	Wind	24.96	31.64	37.87	43.52	60.51	63.67	64.02	64.24	64.53	65.36	65.36	65.36	65.36	65.37
2308	Total	117.02	124.53	132.04	139.43	158.60	163.64	166.36	168.56	170.56	171.88	172.33	172.88	173.91	174.96
2309															
2310	**Generation (billion kilowatthours)**														
2311	Conventional Hydropower	256.42	273.54	243.51	261.85	270.43	277.78	291.46	301.43	310.07	310.08	310.10	310.11	282.75	310.13
2312	Geothermal	14.95	15.21	16.91	16.91	18.84	20.66	20.86	20.86	20.86	20.86	20.86	20.87	22.36	22.36
2313	Municipal Waste	17.62	18.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36
2314	Wood and Other Biomass	38.34	38.27	40.05	41.71	49.42	57.69	64.29	101.21	135.54	199.36	221.35	235.40	249.95	264.08
2315	Solar 5/	2.08	3.15	4.82	6.79	8.94	11.13	12.85	14.78	16.87	16.96	17.07	17.20	17.34	17.50
2316	Wind	55.52	71.06	91.75	110.84	178.08	187.48	187.95	188.77	189.28	191.68	191.69	191.70	191.70	191.70
2317	Total	384.94	419.59	414.39	455.46	543.07	572.11	594.77	644.41	689.97	756.31	778.43	792.64	781.46	823.14
2318															
2319															
2320															
2321															
2322	1/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity,														
2323	or electricity and heat, to the public.														
2324	2/ Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS														
2325	potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity														
2326	generation and is only available after 2025.														
2327	3/ Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed														
2328	to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal														
2329	waste stream contains petroleum-derived plastics and other non-renewable sources.														
2330	4/ Facilities co-firing biomass and coal are classified as coal.														
2331	5/ Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2008, EIA estimates														
2332	that as much as 237 megawatts of remote electricity														
2333	generation PV applications (i.e., off-grid power systems) were in service in 2008, plus an additional 550 megawatts in														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2293	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	1.0%
2294	75.63	85.03	94.32	103.67	110.83	118.14	121.90	122.65	122.22	123.00	123.81	124.65	125.47	126.27	6.0%
2295	14.46	14.60	14.76	14.94	15.14	15.39	15.67	15.97	16.30	16.58	16.86	17.15	17.48	17.87	8.1%
2296	2.30	2.31	2.32	2.34	2.35	2.37	2.39	2.42	2.44	2.47	2.50	2.54	2.58	2.63	9.6%
2297	**98.44**	**107.99**	**117.45**	**127.00**	**134.38**	**141.95**	**146.02**	**147.09**	**147.02**	**148.10**	**149.22**	**150.39**	**151.58**	**152.83**	**5.7%**
2298															
2299															
2300															
2301															
2302	79.65	82.49	82.51	82.51	82.51	82.51	82.51	82.52	82.52	82.52	82.52	82.52	82.52	82.52	0.2%
2303	3.09	3.31	3.55	3.83	4.12	4.44	4.82	5.25	5.61	5.90	6.06	6.16	6.30	6.41	3.8%
2304	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	3.67	0.0%
2305	13.63	14.80	15.96	17.15	18.11	19.09	19.60	19.70	19.67	19.77	19.88	20.00	20.11	20.22	4.1%
2306	10.82	10.93	11.05	11.18	11.33	11.50	11.70	11.91	12.13	12.31	12.49	12.68	12.89	14.06	7.4%
2307	65.37	68.80	72.76	77.30	82.53	88.54	95.45	103.40	112.54	114.91	114.93	114.96	114.99	116.07	5.1%
2308	176.23	184.00	189.50	195.65	202.26	209.76	217.75	226.46	236.14	239.09	239.56	239.99	240.48	242.96	2.6%
2309															
2310															
2311	310.39	321.49	321.61	321.62	321.63	321.64	321.65	321.72	321.73	321.74	321.75	321.07	321.08	312.39	0.5%
2312	22.36	24.07	26.04	28.31	30.62	33.28	36.34	39.86	42.77	45.09	46.43	47.25	48.38	49.33	4.6%
2313	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	17.36	-0.2%
2314	274.92	283.16	293.28	303.43	308.86	315.84	316.08	312.00	303.20	292.49	278.37	281.67	295.29	295.08	8.2%
2315	17.67	17.86	18.07	18.31	18.56	18.86	19.20	19.55	19.93	20.25	20.57	20.90	21.26	24.24	8.2%
2316	191.71	203.78	217.44	233.16	250.59	268.35	291.32	316.29	340.52	347.41	347.46	347.50	347.55	351.27	6.3%
2317	834.41	867.72	893.80	922.19	947.63	975.33	1001.95	1026.78	1045.51	1044.33	1031.94	1035.76	1050.92	1049.68	3.6%
2318															
2319															
2320															
2321															
2322															
2323															
2324															
2325															
2326															
2327															
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2330															
2331															
2332															
2333															

cesbingbk.d100611a	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021

communications, transportation, and assorted other
non-grid-connected, specialized applications. See U.S. Energy Information Administration, Annual Energy Review
2009, DOE/EIA-0384(2009) (Washington, DC, August 2010), Table 10.9 (annual PV shipments, 1989-2008).
The approach used to develop the estimate,
based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV.
It will overestimate the size of the stock, because
shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier
will be retired from service or abandoned.

6/ Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed
to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration
estimates that in 2009 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream
containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration,
Methodology for Allocating Municipal Solid Waste to Biogenic and Nono-Biogenic Energy, (Washington, DC, May 2007).

7/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors;
and small on-site generating systems in the residential, commercial, and industrial sectors used
primarily for own-use generation, but which may also sell some power to the grid.

8/ Represents own-use industrial hydroelectric power.

9/ Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion
of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009
are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 capacity: U.S. Energy Information Administration (EIA), Form EIA-860,
"Annual Electric Generator Report" (preliminary). 2008 and 2009 generation: EIA,
Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010).
Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

17. Renewable Energy Consumption by Sector and Source

(quadrillion Btu, unless otherwise noted)

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2334															
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2375															
2376															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2377															
2378	*Sector and Source*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2379															
2380	**Marketed Renewable Energy 1/**														
2381															
2382	**Residential (wood)**	**0.44**	**0.43**	**0.42**	**0.42**	**0.41**	**0.40**	**0.40**	**0.40**	**0.41**	**0.41**	**0.41**	**0.42**	**0.42**	**0.42**
2383															
2384	**Commercial (biomass)**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
2385															
2386	**Industrial 2/**	**2.50**	**2.09**	**2.22**	**2.56**	**2.56**	**2.71**	**2.65**	**2.71**	**2.73**	**2.82**	**2.90**	**3.01**	**3.15**	**3.26**
2387	Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
2388	Municipal Waste 3/	0.16	0.17	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
2389	Biomass	1.33	1.22	1.28	1.41	1.53	1.67	1.60	1.66	1.66	1.70	1.72	1.73	1.76	1.78
2390	Biofuels Heat and Coproducts	0.98	0.67	0.74	0.94	0.81	0.83	0.84	0.85	0.86	0.91	0.97	1.06	1.18	1.27
2391															
2392	**Transportation**	**0.87**	**0.99**	**1.16**	**1.26**	**1.40**	**1.44**	**1.45**	**1.51**	**1.58**	**1.67**	**1.77**	**1.86**	**1.99**	**1.96**
2393	Ethanol used in E85 4/	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.07	0.12	0.16	0.21	0.13
2394	Ethanol used in Gasoline Blending	0.83	0.95	1.11	1.15	1.27	1.29	1.31	1.33	1.35	1.37	1.41	1.44	1.49	1.50
2395	Biodiesel used in Distillate Blending	0.04	0.04	0.04	0.09	0.12	0.14	0.13	0.15	0.18	0.19	0.19	0.20	0.20	0.20
2396	Liquids from Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.03	0.04	0.06	0.08	0.11
2397	Renewable Diesel and Gasoline 5/	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02
2398															
2399	**Electric Power 6/**	**3.67**	**3.89**	**3.85**	**4.20**	**5.05**	**5.32**	**5.52**	**6.02**	**6.44**	**7.08**	**7.27**	**7.37**	**7.25**	**7.58**
2400	Conventional Hydroelectric	2.49	2.66	2.37	2.55	2.63	2.70	2.83	2.93	3.01	3.01	3.01	3.01	2.74	3.01
2401	Geothermal	0.31	0.32	0.36	0.36	0.41	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.52	0.52
2402	Biogenic Municipal Waste 7/	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
2403	Biomass	0.21	0.11	0.12	0.11	0.15	0.20	0.26	0.66	0.99	1.60	1.79	1.90	2.00	2.05
2404	Dedicated Plants	0.13	0.12	0.10	0.09	0.07	0.07	0.06	0.19	0.18	0.17	0.17	0.17	0.19	0.18
2405	Cofiring	0.08	-0.01	0.02	0.02	0.08	0.13	0.20	0.47	0.81	1.43	1.62	1.72	1.81	1.88
2406	Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
2407	Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
2408	Wind	0.55	0.70	0.90	1.08	1.74	1.83	1.84	1.84	1.84	1.87	1.87	1.87	1.87	1.87
2409															
2410	**Total Marketed Renewable Energy**	**7.58**	**7.51**	**7.76**	**8.54**	**9.52**	**9.99**	**10.14**	**10.76**	**11.27**	**12.09**	**12.46**	**12.77**	**12.91**	**13.32**
2411															
2412	**Sources of Ethanol**														
2413	From Corn and Other Starch	0.78	0.93	1.11	1.15	1.24	1.26	1.26	1.24	1.24	1.27	1.30	1.35	1.40	1.34
2414	From Cellulose	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.04	0.06	0.10	0.15	0.22
2415	Net Imports	0.04	0.02	0.00	0.01	0.03	0.03	0.04	0.07	0.10	0.13	0.16	0.14	0.14	0.07

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2377															**2009-**
2378	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2379															
2380															
2381															
2382	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.43**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**-0.1%**
2383															
2384	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.0%**
2385															
2386	**3.38**	**3.56**	**3.76**	**3.92**	**4.03**	**4.13**	**4.26**	**4.30**	**4.34**	**4.37**	**4.38**	**4.48**	**4.52**	**4.52**	**3.0%**
2387	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.0%
2388	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.1%
2389	1.80	1.81	1.81	1.83	1.83	1.83	1.82	1.82	1.83	1.82	1.81	1.81	1.81	1.80	1.5%
2390	1.37	1.54	1.73	1.88	1.99	2.09	2.23	2.26	2.30	2.34	2.36	2.46	2.50	2.51	5.2%
2391															
2392	**2.17**	**2.33**	**2.53**	**2.69**	**2.84**	**2.97**	**3.20**	**3.27**	**3.37**	**3.46**	**3.50**	**3.65**	**3.70**	**3.72**	**5.2%**
2393	0.27	0.39	0.53	0.61	0.71	0.64	0.84	0.76	0.73	0.75	0.76	0.74	0.74	0.74	25.9%
2394	1.49	1.47	1.46	1.45	1.39	1.47	1.38	1.47	1.50	1.50	1.51	1.55	1.55	1.56	1.9%
2395	0.24	0.24	0.24	0.24	0.24	0.24	0.25	0.23	0.25	0.25	0.25	0.25	0.25	0.25	7.2%
2396	0.15	0.21	0.29	0.38	0.49	0.61	0.71	0.79	0.88	0.94	0.97	1.09	1.13	1.14	- -
2397	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	- -
2398															
2399	**7.60**	**7.86**	**8.07**	**8.30**	**8.53**	**8.78**	**9.06**	**9.36**	**9.61**	**9.64**	**9.53**	**9.59**	**9.79**	**9.83**	**3.6%**
2400	3.02	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.12	3.12	3.04	0.5%
2401	0.52	0.57	0.63	0.70	0.77	0.85	0.94	1.04	1.13	1.20	1.24	1.27	1.30	1.33	5.6%
2402	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.0%
2403	2.08	2.06	2.07	2.08	2.06	2.06	2.02	1.97	1.89	1.78	1.64	1.68	1.84	1.88	11.6%
2404	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20	0.20	2.0%
2405	1.89	1.88	1.89	1.90	1.87	1.87	1.83	1.79	1.70	1.58	1.44	1.48	1.63	1.68	- -
2406	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	4.9%
2407	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.04	18.6%
2408	1.87	1.99	2.12	2.27	2.45	2.62	2.85	3.09	3.33	3.40	3.40	3.40	3.40	3.44	6.3%
2409															
2410	**13.68**	**14.29**	**14.90**	**15.45**	**15.94**	**16.42**	**17.06**	**17.46**	**17.85**	**18.00**	**17.95**	**18.25**	**18.53**	**18.61**	**3.6%**
2411															
2412															
2413	1.29	1.31	1.37	1.38	1.39	1.38	1.48	1.46	1.47	1.47	1.47	1.50	1.51	1.51	1.9%
2414	0.29	0.37	0.43	0.48	0.48	0.48	0.48	0.48	0.47	0.47	0.47	0.47	0.47	0.47	48.5%
2415	0.17	0.18	0.19	0.21	0.22	0.24	0.26	0.29	0.29	0.31	0.33	0.33	0.32	0.33	12.2%

cesbingbk.d100611a	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total U.S. Supply of Ethanol	**0.83**	**0.95**	**1.11**	**1.16**	**1.27**	**1.29**	**1.31**	**1.33**	**1.36**	**1.44**	**1.52**	**1.60**	**1.69**	**1.63**
Sources of Biodiesel														
Soy Based	0.08	0.06	0.05	0.08	0.08	0.10	0.10	0.10	0.13	0.13	0.13	0.14	0.14	0.14
Yellow Grease	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
White Grease	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Net Imports	-0.05	-0.02	-0.01	-0.01	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Total	**0.04**	**0.04**	**0.04**	**0.09**	**0.12**	**0.14**	**0.13**	**0.15**	**0.18**	**0.19**	**0.19**	**0.20**	**0.20**	**0.20**
Nonmarketed Renewable Energy														
Selected Consumption 8/														
Residential	**0.01**	**0.01**	**0.02**	**0.03**	**0.04**	**0.05**	**0.06**	**0.07**	**0.08**	**0.08**	**0.08**	**0.08**	**0.09**	**0.09**
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Commercial	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

1/ Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table 2.

2/ Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

3/ Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.

4/ Excludes motor gasoline component of E85.

5/ Renewable feedstocks for the on-site production of diesel and gasoline.

6/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

7/ Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2009 approximately .3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration,

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2416	**1.76**	**1.86**	**1.99**	**2.06**	**2.09**	**2.11**	**2.22**	**2.23**	**2.22**	**2.25**	**2.27**	**2.29**	**2.30**	**2.31**	**3.5%**
2417															
2418															
2419	0.18	0.18	0.17	0.17	0.18	0.17	0.18	0.17	0.18	0.19	0.18	0.18	0.18	0.18	4.5%
2420	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	5.9%
2421	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	10.1%
2422	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2423	**0.24**	**0.24**	**0.24**	**0.24**	**0.24**	**0.24**	**0.25**	**0.23**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**7.2%**
2424															
2425															
2426															
2427															
2428															
2429	**0.09**	**0.09**	**0.09**	**0.09**	**0.09**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.11**	**0.11**	**0.11**	**8.4%**
2430	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	2.1%
2431	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	8.7%
2432	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	9.9%
2433	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	11.1%
2434															
2435	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**1.6%**
2436	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.8%
2437	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	4.6%
2438	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.0%
2439															
2440															
2441															
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2457	Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy, (Washington, DC, May 2007).														
2458	8/ Includes selected renewable energy consumption data for which the energy is not bought or sold, either														
2459	directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not														
2460	estimate or project total consumption of nonmarketed renewable energy.														
2461	- - = Not applicable.														
2462	Btu = British thermal unit.														
2463	Note: Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind.														
2464	Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 9,854 Btu per														
2465	kilowatthour. Totals may not equal sum of components due to independent rounding. Data for 2008 and														
2466	2009 are model results and may differ slightly from official EIA data reports.														
2467	Sources: 2008 and 2009 ethanol: U.S. Energy Information Administration (EIA),														
2468	Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009														
2469	electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other														
2470	2008 and 2009 values: EIA, Office of Integrated Analysis and Forecasting.														
2471	Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														
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1	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
2457															
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cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

18. Carbon Dioxide Emissions by Sector and Source

(million metric tons carbon dioxide equivalent, unless otherwise noted)

Sector and Source	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Residential														
Petroleum	85	83	78	79	77	75	74	73	72	71	70	69	68	67
Natural Gas	266	259	260	259	261	262	263	261	260	259	259	260	261	260
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Electricity 1/	878	824	898	819	806	779	766	686	694	678	670	667	678	671
Total	**1229**	**1166**	**1237**	**1159**	**1144**	**1117**	**1104**	**1021**	**1028**	**1009**	**1000**	**996**	**1007**	**998**
Commercial														
Petroleum	46	44	39	39	40	39	39	39	39	38	38	38	38	38
Natural Gas	171	169	169	175	177	180	183	182	182	182	183	185	185	186
Coal	7	6	6	6	6	6	6	6	6	6	6	6	6	6
Electricity 1/	850	800	833	819	806	797	794	722	737	728	725	726	742	740
Total	**1074**	**1018**	**1046**	**1039**	**1028**	**1021**	**1022**	**949**	**964**	**954**	**952**	**955**	**971**	**969**
Industrial 2/														
Petroleum	376	343	366	373	403	410	410	415	411	409	407	405	404	404
Natural Gas 3/	407	383	412	431	443	465	474	476	474	475	477	479	480	479
Coal	173	128	149	149	150	154	153	160	159	159	159	159	160	161
Electricity 1/	642	533	579	588	588	602	589	528	528	515	506	500	506	497
Total	**1598**	**1387**	**1505**	**1542**	**1584**	**1631**	**1626**	**1579**	**1571**	**1558**	**1549**	**1543**	**1550**	**1542**
Transportation														
Petroleum 4/	1896	1816	1824	1834	1845	1869	1874	1873	1874	1873	1872	1871	1870	1881
Natural Gas 5/	37	34	37	36	36	36	37	39	38	38	39	39	40	40
Electricity 1/	4	4	4	4	4	4	4	4	4	4	5	5	5	5
Total	**1937**	**1854**	**1865**	**1874**	**1885**	**1910**	**1915**	**1916**	**1917**	**1916**	**1915**	**1915**	**1915**	**1926**
Electric Power 6/														
Petroleum	40	34	35	34	34	34	34	34	34	34	34	34	34	34
Natural Gas	362	373	398	374	337	338	343	455	434	438	453	466	471	471
Coal	1959	1742	1869	1810	1820	1797	1766	1440	1484	1440	1407	1386	1414	1396
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2498															
2499															
2500															
2501															
2502															**2009-**
2503	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2504															
2505															
2506	66	65	65	64	63	62	62	61	61	60	60	59	59	58	-1.3%
2507	260	260	261	261	261	261	262	261	261	260	261	259	258	258	0.0%
2508	1	1	1	1	1	1	1	1	1	1	1	1	0	0	-1.1%
2509	675	664	658	649	640	626	610	592	569	546	523	516	531	518	-1.8%
2510	**1002**	**990**	**985**	**974**	**964**	**950**	**934**	**914**	**891**	**868**	**845**	**835**	**848**	**835**	**-1.3%**
2511															
2512															
2513	38	38	38	38	37	37	37	37	37	37	37	37	37	37	-0.6%
2514	186	187	188	189	190	192	193	195	197	199	200	202	203	205	0.8%
2515	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0.0%
2516	747	738	734	729	722	709	693	676	653	630	605	600	620	606	-1.1%
2517	**977**	**969**	**965**	**961**	**955**	**944**	**929**	**914**	**893**	**872**	**849**	**845**	**866**	**855**	**-0.7%**
2518															
2519															
2520	404	403	403	402	401	400	398	398	398	399	399	399	401	400	0.6%
2521	477	477	476	477	478	479	483	485	490	493	496	499	500	503	1.1%
2522	164	172	176	180	184	189	195	200	207	213	220	227	233	240	2.4%
2523	494	480	469	457	442	423	402	382	360	338	316	306	309	297	-2.2%
2524	**1539**	**1532**	**1524**	**1515**	**1504**	**1491**	**1478**	**1465**	**1455**	**1444**	**1431**	**1431**	**1443**	**1440**	**0.1%**
2525															
2526															
2527	1876	1875	1874	1880	1885	1899	1898	1912	1931	1947	1961	1975	1992	2009	0.4%
2528	41	41	41	42	42	42	43	43	44	45	45	46	47	50	1.5%
2529	5	6	6	6	6	6	7	7	7	7	7	7	7	7	2.2%
2530	**1922**	**1922**	**1921**	**1928**	**1933**	**1947**	**1947**	**1962**	**1982**	**1998**	**2013**	**2028**	**2046**	**2066**	**0.4%**
2531															
2532															
2533	34	34	34	34	34	34	34	34	33	33	33	33	33	33	0.0%
2534	480	484	482	483	487	493	499	499	512	536	554	581	604	651	2.2%
2535	1395	1359	1340	1311	1277	1227	1168	1112	1031	939	851	802	818	732	-3.3%
2536	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.0%

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Total	**2374**	**2160**	**2314**	**2230**	**2204**	**2182**	**2154**	**1941**	**1964**	**1925**	**1906**	**1898**	**1931**	**1913**
Total by Fuel														
Petroleum 3/	2444	2319	2343	2360	2399	2428	2431	2434	2430	2425	2420	2416	2413	2424
Natural Gas	1243	1218	1275	1276	1253	1281	1299	1414	1388	1393	1411	1429	1437	1436
Coal	2139	1877	2023	1966	1977	1958	1925	1606	1650	1606	1573	1552	1580	1564
Other 7/	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Total	**5838**	**5426**	**5654**	**5613**	**5641**	**5679**	**5667**	**5466**	**5479**	**5437**	**5416**	**5409**	**5443**	**5435**
Carbon Dioxide Emissions (tons carbon dioxide equivalent per person)	**19.1**	**17.6**	**18.2**	**17.9**	**17.8**	**17.8**	**17.5**	**16.8**	**16.6**	**16.4**	**16.1**	**16.0**	**15.9**	**15.7**

1/ Emissions from the electric power sector are distributed to the end-use sectors.

2/ Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

3/ Includes lease and plant fuel.

4/ This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2009, international bunker fuels accounted for 86 to 130 million metric tons annually.

5/ Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

6/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

7/ Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

- - = Not applicable.

Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related CO2 emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 emissions and emission factors: U.S. Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009) (Washington, DC, December 2010). Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2537	**1922**	**1888**	**1867**	**1840**	**1810**	**1765**	**1712**	**1657**	**1589**	**1520**	**1451**	**1429**	**1467**	**1428**	**-1.6%**
2538															
2539															
2540	2418	2414	2413	2417	2420	2432	2429	2442	2461	2477	2491	2504	2522	2538	0.3%
2541	1444	1449	1449	1451	1458	1466	1479	1483	1503	1533	1557	1588	1612	1667	1.2%
2542	1566	1537	1522	1497	1467	1422	1368	1319	1245	1159	1077	1035	1058	978	-2.5%
2543	12	12	12	12	12	12	12	12	12	12	12	12	12	12	0.0%
2544	**5440**	**5412**	**5395**	**5378**	**5357**	**5332**	**5289**	**5256**	**5221**	**5181**	**5137**	**5139**	**5204**	**5195**	**-0.2%**
2545															
2546															
2547	**15.6**	**15.4**	**15.2**	**15.0**	**14.8**	**14.6**	**14.4**	**14.2**	**14.0**	**13.7**	**13.5**	**13.4**	**13.5**	**13.3**	**-1.1%**
2548															
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	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2579															
2580															
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2599															
2600	**19. Energy-Related Carbon Dioxide Emissions by End Use**														
2601	**(million metric tons carbon dioxide equivalent, unless otherwise noted)**														
2602															
2603	*Sector and Source*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2604															
2605	**Residential**														
2606	Space Heating	292.69	279.59	281.60	278.52	275.60	275.07	274.54	267.79	267.06	263.97	262.64	261.74	262.17	260.13
2607	Space Cooling	162.47	147.71	201.42	141.27	140.19	138.52	137.03	122.73	123.57	120.89	119.52	119.06	121.20	120.24
2608	Water Heating	164.41	160.31	162.97	162.49	162.78	161.97	161.74	152.99	153.63	151.30	150.33	149.82	151.05	149.61
2609	Refrigeration	69.77	65.08	65.92	64.17	62.42	60.76	59.14	52.62	52.79	50.95	49.84	49.08	49.56	48.59
2610	Cooking	32.95	32.03	32.76	32.71	32.60	32.41	32.39	30.73	31.22	30.93	30.89	30.93	31.44	31.33
2611	Clothes Dryers	37.79	35.69	36.39	35.55	35.05	34.32	33.76	30.36	30.41	29.38	28.74	28.29	28.50	27.95
2612	Freezers	14.84	13.90	14.15	13.85	13.55	13.25	13.02	11.70	11.84	11.51	11.34	11.25	11.43	11.27
2613	Lighting	134.22	125.69	127.95	123.29	119.50	103.79	97.19	84.87	84.38	81.22	79.47	78.36	76.69	74.29
2614	Clothes Washers 1/	6.31	5.85	5.88	5.66	5.44	5.23	5.05	4.45	4.40	4.17	4.00	3.87	3.84	3.73
2615	Dishwashers 1/	17.17	16.09	16.41	16.08	15.72	15.31	15.04	13.49	13.65	13.27	13.09	13.01	13.28	13.17
2616	Color Televisions and Set-Top Boxes	62.03	59.44	61.51	60.12	58.73	56.88	55.42	49.34	49.65	48.22	47.58	47.31	48.27	47.81
2617	Personal Computers and Related Equipm	32.17	31.33	32.42	32.00	30.53	29.18	28.52	25.19	25.52	24.80	24.48	24.29	24.70	24.42

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2579															
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2602															**2009-**
2603	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2604															
2605															
2606	259.48	257.95	257.36	255.32	253.97	252.39	251.31	248.93	247.03	244.95	243.29	240.99	240.48	238.62	-0.6%
2607	121.09	119.23	117.90	116.47	114.79	112.27	109.11	106.00	102.00	98.08	93.91	92.73	95.31	92.77	-1.8%
2608	149.46	147.74	146.64	144.53	142.65	140.19	137.70	134.39	130.87	127.23	123.88	121.51	121.59	119.60	-1.1%
2609	48.47	47.42	46.85	46.02	45.31	44.31	43.25	41.97	40.42	38.86	37.37	36.97	38.25	37.55	-2.1%
2610	31.54	31.38	31.41	31.24	31.14	30.90	30.65	30.22	29.72	29.20	28.73	28.60	29.15	28.94	-0.4%
2611	27.86	27.28	26.95	26.48	26.11	25.58	25.02	24.32	23.50	22.67	21.86	21.55	22.08	21.61	-1.9%
2612	11.30	11.10	10.99	10.81	10.64	10.39	10.12	9.80	9.41	9.02	8.65	8.53	8.80	8.62	-1.8%
2613	73.44	71.25	69.81	67.99	66.37	64.31	62.17	59.74	57.00	54.32	51.76	50.66	51.82	50.28	-3.5%
2614	3.69	3.61	3.57	3.53	3.50	3.43	3.36	3.26	3.14	3.02	2.91	2.87	2.97	2.91	-2.6%
2615	13.29	13.15	13.12	13.01	12.91	12.70	12.47	12.16	11.77	11.37	10.97	10.89	11.31	11.13	-1.4%
2616	48.19	47.56	47.33	46.76	46.28	45.43	44.50	43.31	41.85	40.32	38.82	38.39	39.65	38.85	-1.6%
2617	24.43	23.98	23.79	23.43	23.11	22.62	22.10	21.45	20.65	19.82	19.01	18.76	19.35	18.93	-1.9%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2618	Furnace Fans and Boiler Circulation Pum	25.57	24.67	25.15	25.56	25.31	25.23	25.31	22.97	23.46	23.06	22.98	23.02	23.59	24.01
2619	Other Uses	174.01	165.10	172.86	167.47	166.59	165.19	165.58	151.90	156.10	154.85	155.16	156.25	161.14	161.77
2620	Discrepancy 2/	2.85	3.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2621	**Total Residential**	**1229.24**	**1166.29**	**1237.39**	**1158.74**	**1144.00**	**1117.11**	**1103.73**	**1021.13**	**1027.69**	**1008.55**	**1000.04**	**996.28**	**1006.86**	**998.31**
2622															
2623	**Commercial**														
2624	Space Heating 3/	127.32	128.25	127.75	129.17	127.57	128.05	129.01	125.45	124.96	124.13	124.08	124.22	124.26	123.68
2625	Space Cooling 3/	92.96	85.69	107.38	92.59	91.45	90.19	89.45	80.60	81.16	79.13	77.90	77.25	78.27	77.38
2626	Water Heating 3/	42.12	41.58	42.22	42.72	42.98	43.30	43.84	42.38	42.61	42.52	42.71	42.99	43.45	43.55
2627	Ventilation	92.45	89.19	92.42	92.35	91.85	91.47	91.59	83.35	85.10	84.04	83.82	83.99	85.89	85.54
2628	Cooking	13.16	13.28	13.73	13.87	13.96	14.10	14.29	13.95	14.02	14.01	14.09	14.19	14.34	14.39
2629	Lighting	194.26	182.83	185.03	181.38	177.82	174.39	172.65	155.72	157.83	154.91	153.58	153.07	155.64	154.25
2630	Refrigeration	75.47	70.55	70.82	68.23	65.51	63.01	61.19	54.32	54.25	52.45	51.29	50.51	50.89	50.05
2631	Office Equipment (PC)	41.33	38.12	38.31	36.14	33.55	32.24	31.25	28.07	28.37	27.70	27.29	26.98	27.24	26.80
2632	Office Equipment (non-PC)	44.27	44.12	47.37	48.29	48.28	48.94	50.19	47.11	49.40	49.79	50.42	50.98	52.34	52.46
2633	Other Uses 4/	350.35	324.34	321.19	334.13	335.28	335.50	338.39	318.32	325.82	325.27	327.21	330.37	338.76	341.03
2634	**Total Commercial**	**1073.69**	**1017.96**	**1046.21**	**1038.86**	**1028.25**	**1021.17**	**1021.84**	**949.26**	**963.51**	**953.95**	**952.39**	**954.56**	**971.08**	**969.13**
2635															
2636															
2637	**Industrial**														
2638	**Manufacturing**														
2639	Refining	260.03	258.60	266.36	267.89	281.84	282.05	280.98	284.57	284.72	284.38	283.92	284.26	284.77	284.37
2640	Food Products	107.10	102.49	105.24	105.46	102.85	103.80	105.00	100.47	102.11	101.81	101.62	101.79	102.71	102.88
2641	Paper Products	100.00	89.65	94.70	96.82	99.58	101.93	94.00	91.45	90.67	90.88	89.86	88.67	88.63	88.05
2642	Bulk Chemicals	282.56	263.05	284.43	290.17	290.46	296.84	298.23	286.14	281.99	277.16	274.34	272.07	272.34	271.32
2643	Glass	24.31	20.02	19.68	20.24	22.52	23.28	22.83	21.67	21.65	21.63	21.57	21.62	21.90	22.07
2644	Cement Manufacturing	36.59	28.55	27.52	27.39	28.77	31.94	32.68	31.84	31.45	31.59	31.60	31.59	31.67	31.70
2645	Iron and Steel	118.67	75.90	106.18	111.32	108.90	114.34	108.89	101.74	99.78	100.27	100.15	99.78	100.51	100.95
2646	Aluminum	31.20	30.81	31.15	30.87	30.31	30.12	29.65	27.63	27.45	26.95	26.44	26.05	26.04	25.54
2647	Fabricated Metal Products	43.03	38.34	40.54	41.51	44.71	46.54	45.69	42.26	42.64	41.96	41.37	41.08	41.32	41.20
2648	Machinery	26.22	22.37	23.71	26.03	26.99	28.09	28.56	25.62	25.89	25.67	25.52	25.58	25.97	26.14
2649	Computers and Electronics	37.33	32.51	35.65	36.06	36.62	38.52	39.37	36.65	37.16	37.01	37.02	37.24	38.10	37.87
2650	Transportation Equipment	52.06	45.42	48.61	53.38	60.06	64.47	65.01	58.17	56.78	54.27	53.03	52.60	52.69	51.48
2651	Electrical Equipment	8.42	7.45	8.03	8.47	9.99	9.93	9.55	8.55	8.47	8.23	8.10	8.01	8.09	8.12
2652	Wood Products	19.15	17.64	18.20	20.80	22.08	23.58	23.45	21.33	21.19	20.66	20.35	20.01	19.99	19.39
2653	Plastics	42.81	37.77	41.61	42.46	42.64	42.62	41.87	37.94	38.22	37.45	36.78	36.30	36.38	35.95
2654	Balance of Manufacturing	159.82	143.04	147.09	149.05	151.57	153.42	152.03	142.88	143.92	142.41	141.67	141.51	142.04	140.17
2655	**Total Manufacturing**	**1349.30**	**1213.61**	**1298.69**	**1327.92**	**1359.90**	**1391.47**	**1377.79**	**1318.91**	**1314.13**	**1302.33**	**1293.34**	**1288.16**	**1293.16**	**1287.20**
2656	**Nonmanufacturing**														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2618	24.26	23.99	23.92	23.65	23.39	22.94	22.42	21.77	20.96	20.11	19.28	18.99	19.55	19.11	-1.0%
2619	165.01	164.44	165.15	164.67	164.11	162.44	160.30	157.01	153.03	148.54	144.10	143.05	147.85	145.63	-0.5%
2620	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2621	**1001.52**	**990.05**	**984.79**	**973.91**	**964.28**	**949.90**	**934.48**	**914.32**	**891.35**	**867.51**	**844.53**	**834.51**	**848.19**	**834.56**	**-1.3%**
2622															
2623															
2624	123.48	122.82	122.31	121.80	121.29	120.68	119.96	119.37	118.56	117.59	116.49	115.66	115.38	114.32	-0.4%
2625	77.64	76.28	75.24	74.15	72.94	71.18	69.03	66.93	64.31	61.89	59.47	58.86	60.44	58.74	-1.4%
2626	43.81	43.81	43.86	43.90	43.92	43.85	43.72	43.63	43.43	43.18	42.88	42.78	42.95	42.68	0.1%
2627	86.24	85.01	84.16	83.17	81.97	80.10	77.75	75.38	72.29	69.18	65.93	64.78	66.23	64.12	-1.3%
2628	14.47	14.50	14.54	14.59	14.64	14.67	14.68	14.72	14.74	14.74	14.74	14.78	14.88	14.89	0.4%
2629	154.89	152.19	150.35	148.25	145.89	142.42	138.16	133.90	128.44	123.03	117.37	115.47	118.16	114.44	-1.8%
2630	49.94	48.84	48.09	47.29	46.48	45.33	44.00	42.69	41.01	39.31	37.57	37.13	38.24	37.33	-2.4%
2631	26.64	26.06	25.82	25.61	25.35	24.89	24.24	23.59	22.71	21.77	20.81	20.51	21.07	20.51	-2.4%
2632	53.27	52.97	53.03	53.00	52.88	52.28	51.32	50.28	48.66	46.97	45.18	44.90	46.46	45.57	0.1%
2633	346.36	346.43	348.07	349.29	350.07	348.81	346.34	343.87	339.06	333.92	328.27	330.44	342.57	342.33	0.2%
2634	**976.75**	**968.90**	**965.48**	**961.04**	**955.42**	**944.20**	**929.21**	**914.36**	**893.21**	**871.59**	**848.71**	**845.30**	**866.39**	**854.94**	**-0.7%**
2635															
2636															
2637															
2638															
2639	284.80	292.56	298.32	302.69	307.44	313.60	321.71	329.03	337.43	346.06	354.02	363.64	373.85	381.85	1.5%
2640	103.57	103.20	103.21	103.06	102.64	102.11	101.43	100.60	99.46	98.46	97.33	97.42	98.65	97.93	-0.2%
2641	87.62	86.25	84.81	83.81	82.55	81.43	79.96	78.79	77.49	76.04	74.63	73.87	73.61	72.49	-0.8%
2642	270.35	267.67	264.51	260.55	255.69	250.21	245.25	240.94	236.93	232.91	228.65	226.04	223.68	219.67	-0.7%
2643	22.31	22.36	22.39	22.56	22.55	22.39	22.10	21.81	21.61	21.31	20.90	20.78	20.89	20.80	0.1%
2644	31.49	31.29	31.23	31.24	31.11	30.86	30.40	29.90	29.34	28.70	27.99	27.51	27.03	26.32	-0.3%
2645	100.78	98.82	96.85	95.01	92.73	90.54	88.44	86.68	84.70	82.57	80.17	78.79	77.51	75.09	0.0%
2646	25.20	24.51	23.92	23.31	22.70	22.03	21.31	20.66	19.95	19.24	18.59	18.19	18.02	17.57	-2.1%
2647	41.29	40.80	40.23	39.49	38.67	37.80	36.89	36.02	34.96	33.95	32.94	32.62	32.89	32.22	-0.7%
2648	26.46	26.22	25.95	25.56	25.05	24.54	24.02	23.49	22.72	22.10	21.39	21.29	21.58	21.19	-0.2%
2649	38.35	38.27	38.24	38.09	37.84	37.33	36.44	35.66	34.72	33.58	32.48	32.10	32.67	32.47	0.0%
2650	50.45	49.21	48.61	48.06	47.52	46.96	46.41	45.82	44.89	44.11	43.27	43.45	44.33	43.81	-0.1%
2651	8.25	8.23	8.17	8.08	7.96	7.80	7.63	7.48	7.30	7.13	6.87	6.79	6.95	6.83	-0.3%
2652	19.01	18.54	18.17	18.03	17.79	17.10	16.23	15.57	15.05	14.44	13.60	13.18	13.28	12.84	-1.2%
2653	35.77	34.94	34.14	33.25	32.29	31.24	30.19	29.27	28.16	27.15	26.07	25.75	26.11	25.38	-1.5%
2654	138.82	135.96	133.64	131.62	129.42	126.89	124.20	121.70	119.11	116.65	113.71	112.50	113.06	110.59	-1.0%
2655	**1284.52**	**1278.82**	**1272.39**	**1264.41**	**1253.93**	**1242.82**	**1232.62**	**1223.41**	**1213.82**	**1204.41**	**1192.62**	**1193.92**	**1204.11**	**1197.05**	**-0.1%**
2656															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2657	Agriculture	76.78	74.59	75.99	76.14	74.93	75.73	74.80	72.01	72.25	72.02	71.59	71.15	71.46	70.78
2658	Construction	94.04	78.52	74.90	79.27	88.28	94.21	95.50	94.40	95.49	95.31	94.75	94.76	95.23	94.29
2659	Mining	56.28	49.39	51.28	50.06	49.42	50.95	50.34	47.53	47.28	46.68	46.31	45.83	46.18	45.61
2660	**Total Nonmanufacturing**	**227.10**	**202.50**	**202.17**	**205.47**	**212.63**	**220.89**	**220.64**	**213.95**	**215.02**	**214.00**	**212.65**	**211.73**	**212.87**	**210.68**
2661	Discrepancy 2/	21.38	-28.68	4.43	8.12	10.98	18.89	27.49	46.22	42.23	41.91	42.71	43.29	44.02	43.90
2662	**Total Industrial**	**1597.78**	**1387.43**	**1505.28**	**1541.51**	**1583.51**	**1631.25**	**1625.92**	**1579.08**	**1571.38**	**1558.24**	**1548.69**	**1543.18**	**1550.05**	**1541.79**
2663															
2664	**Transportation**														
2665	Light-Duty Vehicles	1100.28	1072.82	1071.23	1066.76	1065.88	1070.13	1071.08	1070.43	1068.94	1061.47	1052.75	1045.58	1037.57	1042.80
2666	Commercial Light Trucks 5/	44.05	40.28	40.73	42.07	43.41	44.92	45.05	44.90	44.65	44.56	44.48	44.43	44.38	44.37
2667	Bus Transportation	18.85	18.92	18.68	18.73	18.84	18.85	18.92	18.91	18.89	18.92	18.97	18.99	19.03	19.07
2668	Freight Trucks	339.28	306.68	317.13	331.36	341.40	358.14	360.50	360.96	361.07	365.37	370.18	374.33	378.96	383.02
2669	Rail, Passenger	6.19	5.96	6.09	6.09	6.06	6.06	6.10	5.77	5.86	5.83	5.83	5.84	5.94	5.95
2670	Rail, Freight	41.80	37.09	38.45	38.81	40.19	41.14	40.77	37.72	38.45	38.68	39.14	39.16	39.63	39.43
2671	Shipping, Domestic	17.11	15.14	15.45	15.11	15.15	15.53	15.70	16.06	16.04	16.16	16.32	16.45	16.59	16.69
2672	Shipping, International	70.20	60.78	62.00	61.55	61.12	61.24	61.32	61.39	61.46	61.53	61.62	61.69	61.78	61.86
2673	Recreational Boats	17.54	17.86	17.77	17.87	17.97	18.07	18.20	18.30	18.38	18.45	18.51	18.57	18.63	18.75
2674	Air	191.53	188.34	183.10	183.96	185.13	187.31	189.83	191.81	193.85	195.91	197.76	199.55	201.35	203.15
2675	Military Use	50.75	53.27	54.59	53.83	52.11	50.09	49.18	48.79	48.71	48.86	49.09	49.34	49.61	49.88
2676	Lubricants	5.20	4.75	4.84	4.42	4.43	4.49	4.54	4.57	4.59	4.61	4.61	4.62	4.63	4.64
2677	Pipeline Fuel	35.31	34.65	35.30	34.47	33.88	34.14	34.56	36.89	35.90	35.70	35.95	36.25	36.37	36.33
2678	Discrepancy 2/	-0.74	-2.69	-0.73	-0.65	-0.58	-0.51	-0.43	-0.36	-0.28	-0.18	-0.08	0.03	0.14	0.23
2679	**Total Transportation**	**1937.33**	**1853.85**	**1864.66**	**1874.38**	**1884.99**	**1909.60**	**1915.31**	**1916.16**	**1916.51**	**1915.88**	**1915.13**	**1914.85**	**1914.59**	**1926.19**
2680															
2681	**Biogenic Energy Combustion 6/**														
2682	Biomass	196.75	174.96	180.94	191.71	206.78	223.69	222.52	265.41	297.38	358.90	378.76	389.73	401.47	408.93
2683	Biogenic Waste	8.26	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27
2684	Biofuels Heat and Coproducts	91.64	63.10	68.97	88.35	76.19	77.80	79.06	79.39	80.79	85.23	90.71	99.85	111.08	119.10
2685	Ethanol	56.60	64.86	76.09	79.15	86.99	88.39	89.91	91.05	92.94	98.45	104.24	109.23	115.86	111.63
2686	Biodiesel	2.93	3.07	3.18	6.45	8.56	9.89	9.18	10.93	13.15	13.78	13.71	14.26	14.39	14.33
2687	Liquids from Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.09	1.35	1.88	2.39	3.14	4.24	5.92	8.18
2688	Green liquids	0.00	0.00	0.49	0.71	0.82	0.89	0.89	0.90	0.90	0.90	0.90	0.91	1.09	1.11
2689	**Total**	**356.19**	**314.26**	**337.93**	**374.64**	**387.60**	**408.93**	**409.93**	**457.31**	**495.31**	**567.93**	**599.72**	**626.49**	**658.08**	**671.54**
2690															
2691															
2692															
2693	1/ Does not include water heating portion of load.														
2694	2/ Represents differences between total emissions by end-use and total emissions by fuel as														
2695	reported in Table 18. Emissions by fuel may reflect benchmarking and other modeling														
2696	adjustments to energy use and the associated emissions that are not assigned to specific end uses.														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2657	70.80	70.65	70.35	69.82	69.66	68.96	68.46	67.70	66.91	65.98	65.22	64.99	65.16	64.71	-0.5%
2658	94.16	93.50	92.76	92.61	92.27	91.23	89.64	88.12	87.23	86.19	85.13	84.62	84.99	84.87	0.3%
2659	45.65	45.00	44.58	44.11	43.68	43.10	42.39	41.80	41.28	40.77	40.56	40.55	41.08	40.80	-0.7%
2660	**210.62**	**209.15**	**207.69**	**206.55**	**205.61**	**203.29**	**200.48**	**197.62**	**195.42**	**192.94**	**190.91**	**190.16**	**191.23**	**190.37**	**-0.2%**
2661	43.91	43.76	43.53	44.08	44.43	44.64	44.42	44.29	45.46	46.44	47.06	47.02	47.93	52.36	- -
2662	**1539.05**	**1531.73**	**1523.61**	**1515.04**	**1503.97**	**1490.75**	**1477.53**	**1465.32**	**1454.69**	**1443.80**	**1430.59**	**1431.10**	**1443.26**	**1439.79**	**0.1%**
2663															
2664															
2665	1034.46	1027.81	1020.71	1020.15	1020.05	1028.13	1023.03	1031.81	1044.82	1054.17	1063.49	1071.50	1082.03	1092.84	0.1%
2666	44.27	44.37	44.52	44.81	45.11	45.33	45.63	45.87	46.32	46.75	47.15	47.52	47.99	48.46	0.7%
2667	19.01	19.05	19.09	19.13	19.16	19.20	19.23	19.28	19.28	19.30	19.36	19.42	19.47	19.52	0.1%
2668	385.04	389.12	393.12	397.98	401.73	405.79	408.83	413.46	417.94	422.71	426.77	431.22	435.83	439.95	1.4%
2669	5.99	5.97	5.97	5.96	5.95	5.90	5.84	5.78	5.66	5.55	5.44	5.44	5.56	5.53	-0.3%
2670	39.50	39.06	39.28	39.29	39.24	39.08	38.84	38.51	38.09	37.80	37.41	37.54	38.38	38.40	0.1%
2671	16.77	16.85	16.87	16.91	16.97	17.11	17.19	17.32	17.42	17.59	17.79	17.94	18.13	18.15	0.7%
2672	61.91	61.99	62.07	62.15	62.22	62.30	62.37	62.45	62.52	62.59	62.67	62.75	62.82	62.90	0.1%
2673	18.84	18.95	19.06	19.18	19.32	19.40	19.54	19.60	19.73	19.87	20.02	20.12	20.27	20.42	0.5%
2674	204.90	206.47	207.98	209.39	210.55	211.63	212.71	213.70	214.74	215.50	216.15	216.73	217.35	217.92	0.6%
2675	50.10	50.38	50.67	50.95	51.23	51.51	51.78	52.07	52.33	52.59	52.86	53.14	53.40	53.67	0.0%
2676	4.66	4.67	4.69	4.71	4.73	4.75	4.76	4.78	4.80	4.81	4.83	4.84	4.86	4.87	0.1%
2677	36.43	36.42	36.34	36.27	36.27	36.37	36.62	36.59	36.86	37.34	37.71	38.25	38.70	41.25	0.7%
2678	0.34	0.45	0.57	0.69	0.79	0.92	1.02	1.13	1.26	1.37	1.49	1.59	1.69	1.80	- -
2679	**1922.24**	**1921.58**	**1920.93**	**1927.57**	**1933.31**	**1947.42**	**1947.38**	**1962.35**	**1981.75**	**1997.96**	**2013.13**	**2028.00**	**2046.47**	**2065.69**	**0.4%**
2680															
2681															
2682	412.92	412.81	414.51	416.59	415.10	415.02	411.23	406.47	398.91	388.06	373.62	377.10	391.91	395.39	3.2%
2683	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	8.27	0.0%
2684	128.89	144.74	162.55	176.56	187.01	196.25	209.10	212.29	215.67	219.52	221.44	230.66	234.21	235.16	5.2%
2685	120.19	127.41	136.46	141.16	143.30	144.06	152.10	152.62	152.10	153.71	155.05	156.93	157.19	157.80	3.5%
2686	17.37	17.44	17.42	17.33	17.79	17.39	17.88	17.04	18.13	18.47	18.29	18.14	18.42	18.49	7.2%
2687	11.31	15.52	20.85	27.55	35.68	44.97	52.09	57.55	64.29	68.96	70.94	79.62	83.01	83.72	- -
2688	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.11	1.11	1.12	- -
2689	**700.08**	**727.31**	**761.18**	**788.57**	**808.27**	**827.08**	**851.79**	**855.35**	**858.50**	**858.10**	**848.73**	**871.82**	**894.12**	**899.94**	**4.1%**
2690															
2691															
2692															
2693															
2694															
2695															
2696															

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

3/ Includes emissions related to fuel consumption for district services.

4/ Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus emissions from residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.

5/ Commercial trucks 8,500 to 10,000 pounds gross vehicle weight rating.

6/ By convention, the direct emissions from biogenic energy sources are excluded from energy-related CO2 emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 emissions and emission factors: U.S. Energy Information Administration (EIA), Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009) (Washington, DC, December 2010). Projections: EIA, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2697															
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1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2739															
2740															
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2745															
2746															
2747															
2748															
2749															
2750	**20. Macroeconomic Indicators**														
2751	**(billion 2005 chain-weighted dollars, unless otherwise noted)**														
2752															
2753	*Indicators*	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2754															
2755	**Real Gross Domestic Product**	**13229**	**12881**	**13221**	**13506**	**14038**	**14587**	**14923**	**15306**	**15688**	**16098**	**16517**	**16929**	**17367**	**17844**
2756	**Components of Real Gross Domestic Product**														
2757	Real Consumption	9265	9154	9299	9506	9731	9990	10190	10436	10676	10907	11138	11372	11635	11934
2758	Real Investment	1957	1516	1763	1845	2201	2504	2496	2581	2654	2734	2817	2904	2995	3101
2759	Real Government Spending	2503	2543	2560	2557	2531	2532	2544	2555	2569	2588	2613	2637	2663	2684
2760	Real Exports	1648	1491	1666	1792	1934	2102	2278	2436	2605	2792	2982	3176	3379	3586
2761	Real Imports	2152	1854	2082	2201	2332	2486	2530	2636	2740	2836	2933	3044	3173	3307
2762															
2763	**Energy Intensity**														
2764	**(thousand Btu per 2005 dollar of GDP)**														
2765	Delivered Energy	5.49	5.33	5.33	5.30	5.19	5.09	5.00	4.90	4.77	4.67	4.56	4.47	4.38	4.28
2766	Total Energy	7.57	7.36	7.40	7.28	7.11	6.95	6.81	6.61	6.46	6.32	6.18	6.05	5.93	5.79
2767															
2768	**Price Indices**														
2769	GDP Chain-type Price Index (2005=1.00C	1.086	1.096	1.106	1.120	1.134	1.154	1.174	1.199	1.223	1.249	1.276	1.301	1.327	1.351
2770	**Consumer Price Index (1982-84=1.00)**														
2771	All-urban	2.15	2.15	2.18	2.21	2.25	2.29	2.34	2.40	2.45	2.51	2.58	2.63	2.69	2.75
2772	Energy Commodities and Services	2.36	1.93	2.09	2.17	2.18	2.27	2.35	2.47	2.55	2.65	2.74	2.82	2.91	2.98
2773	**Wholesale Price Index (1982=1.00)**														
2774	All Commodities	1.90	1.73	1.83	1.86	1.88	1.93	1.96	2.02	2.06	2.10	2.14	2.17	2.22	2.26
2775	Fuel and Power	2.14	1.59	1.84	1.89	1.87	1.92	1.97	2.13	2.22	2.30	2.38	2.45	2.54	2.61
2776	Metals and Metal Products	2.13	1.87	2.04	2.04	2.13	2.31	2.40	2.47	2.50	2.54	2.58	2.62	2.65	2.68
2777	Industrial Commodities excluding Energ	1.81	1.76	1.83	1.85	1.88	1.94	1.97	2.01	2.03	2.06	2.09	2.12	2.14	2.16

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2739															
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2752															**2009-**
2753	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2754															
2755	**18375**	**18889**	**19408**	**19963**	**20497**	**21028**	**21548**	**22074**	**22645**	**23217**	**23776**	**24353**	**24954**	**25562**	**2.7%**
2756															
2757	12257	12578	12902	13251	13591	13936	14278	14619	14988	15369	15744	16120	16509	16901	2.4%
2758	3223	3330	3427	3551	3659	3766	3869	3976	4113	4250	4371	4505	4660	4820	4.5%
2759	2711	2739	2766	2793	2822	2850	2876	2901	2930	2952	2979	3006	3034	3063	0.7%
2760	3798	4019	4251	4488	4725	4969	5224	5493	5773	6065	6364	6677	7003	7340	6.3%
2761	3439	3578	3714	3868	4021	4185	4362	4544	4750	4968	5194	5423	5671	5930	4.6%
2762															
2763															
2764															
2765	4.17	4.08	4.00	3.91	3.82	3.74	3.67	3.60	3.54	3.47	3.41	3.34	3.28	3.22	-1.9%
2766	5.64	5.51	5.39	5.26	5.15	5.04	4.94	4.84	4.75	4.65	4.56	4.46	4.36	4.27	-2.1%
2767															
2768															
2769	1.374	1.399	1.424	1.448	1.473	1.500	1.528	1.557	1.586	1.616	1.648	1.681	1.715	1.750	1.8%
2770															
2771	2.80	2.86	2.92	2.98	3.04	3.10	3.16	3.23	3.30	3.36	3.44	3.51	3.59	3.67	2.1%
2772	3.06	3.16	3.25	3.32	3.42	3.51	3.61	3.71	3.77	3.86	3.96	4.05	4.19	4.31	3.1%
2773															
2774	2.29	2.33	2.37	2.40	2.43	2.47	2.50	2.54	2.57	2.60	2.65	2.68	2.73	2.77	1.8%
2775	2.69	2.78	2.87	2.95	3.03	3.12	3.21	3.30	3.37	3.45	3.56	3.64	3.74	3.86	3.5%
2776	2.69	2.71	2.72	2.74	2.75	2.76	2.77	2.79	2.80	2.81	2.82	2.83	2.84	2.84	1.6%
2777	2.18	2.20	2.22	2.24	2.26	2.27	2.29	2.31	2.33	2.35	2.37	2.38	2.40	2.42	1.2%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2778															
2779	**Interest Rates (percent, nominal)**														
2780	Federal Funds Rate	1.93	0.16	0.15	0.14	2.43	4.33	4.76	5.22	5.03	4.98	4.95	4.87	4.82	4.71
2781	10-Year Treasury Note	3.67	3.26	3.11	2.51	3.98	4.96	5.29	5.79	5.81	5.90	5.92	5.86	5.83	5.75
2782	AA Utility Bond Rate	6.19	5.75	5.12	4.61	5.56	6.44	7.01	7.52	7.58	7.66	7.71	7.70	7.72	7.65
2783															
2784	**Value of Shipments (billion 2005 dollars)**														
2785	Service Sectors	20737	19555	20259	21019	21560	22306	22668	23125	23555	24029	24516	24993	25491	26040
2786	Total Industrial	6720	6017	6244	6562	6898	7294	7377	7445	7488	7573	7673	7784	7894	7982
2787	Agriculture, Mining, and Construction	2039	1821	1793	1845	1979	2094	2147	2206	2241	2263	2286	2313	2337	2349
2788	Manufacturing	4680	4197	4451	4716	4919	5200	5230	5239	5248	5310	5387	5471	5557	5633
2789	Energy Intensive	1635	1551	1638	1691	1716	1776	1775	1777	1778	1795	1808	1821	1838	1858
2790	Non-energy Intensive	3046	2646	2814	3026	3203	3424	3455	3462	3470	3515	3579	3650	3719	3774
2791	Total	27456	25573	26503	27580	28458	29600	30045	30570	31044	31603	32189	32777	33384	34022
2792															
2793	**Population and Employment (millions)**														
2794	Population, with Armed Forces Overseas	305.2	307.8	310.8	313.8	316.9	319.9	323.0	326.2	329.3	332.5	335.6	338.8	342.0	345.2
2795	Population, aged 16 and over	239.4	241.8	244.3	246.8	249.3	251.7	254.1	256.5	259.0	261.6	264.2	266.8	269.4	272.0
2796	Population, over age 65	38.9	39.7	40.4	41.4	42.8	44.2	45.6	47.1	48.5	50.0	51.6	53.3	55.1	56.8
2797	Employment, Nonfarm	136.7	130.9	130.7	133.3	134.6	138.8	140.8	142.2	143.3	144.6	146.0	147.1	148.4	149.8
2798	Employment, Manufacturing	13.4	11.9	11.8	12.3	14.4	15.5	16.5	17.4	17.3	17.1	17.0	17.0	16.9	16.7
2799															
2800	**Key Labor Indicators**														
2801	Labor Force (millions)	154.3	154.2	154.0	155.1	156.1	157.9	159.5	160.7	161.8	163.0	164.2	165.2	166.1	167.1
2802	Nonfarm Labor Productivity (2005=1.00)	1.04	1.07	1.11	1.12	1.13	1.14	1.16	1.18	1.20	1.23	1.25	1.28	1.30	1.33
2803	Unemployment Rate (percent)	5.82	9.28	9.70	9.65	8.75	7.45	7.14	6.91	6.67	6.38	6.10	5.86	5.59	5.44
2804															
2805															
2806	**Key Indicators for Energy Demand**														
2807	Real Disposable Personal Income	10043	10100	10224	10354	10544	10809	11170	11521	11885	12207	12497	12799	13138	13512
2808	Housing Starts (millions)	0.98	0.60	0.65	0.85	1.72	1.85	1.78	1.83	1.88	1.90	1.90	1.91	1.90	1.89
2809	Commercial Floorspace (billion square fe	78.8	80.2	81.2	82.0	82.7	83.5	84.4	85.5	86.6	87.8	89.0	90.2	91.4	92.5
2810	Unit Sales of Light-Duty Vehicles (millions	13.19	10.40	11.38	12.77	15.43	16.89	16.73	16.90	16.91	16.57	16.39	16.46	16.80	17.12
2811															
2812															
2813															
2814															
2815	GDP = Gross domestic product.														
2816	Btu = British thermal unit.														
2817	- - = Not applicable.														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2778															
2779															
2780	4.68	4.77	4.82	4.79	4.82	4.84	4.84	4.89	4.92	4.98	5.03	5.06	5.10	5.07	- -
2781	5.73	5.80	5.81	5.76	5.77	5.77	5.76	5.79	5.80	5.84	5.89	5.93	5.97	5.97	- -
2782	7.66	7.77	7.80	7.75	7.77	7.78	7.78	7.82	7.83	7.89	7.97	8.01	8.08	8.10	- -
2783															
2784															
2785	26665	27302	27927	28567	29180	29782	30358	30944	31555	32159	32756	33349	33935	34495	2.2%
2786	8075	8170	8256	8363	8455	8541	8610	8689	8797	8897	8981	9070	9169	9254	1.7%
2787	2371	2389	2397	2419	2439	2450	2452	2456	2475	2496	2514	2532	2563	2583	1.4%
2788	5704	5781	5859	5944	6017	6091	6158	6233	6322	6401	6466	6538	6606	6671	1.8%
2789	1873	1884	1893	1904	1909	1918	1924	1932	1942	1950	1956	1965	1969	1973	0.9%
2790	3831	3898	3967	4041	4107	4174	4234	4301	4380	4451	4510	4573	4637	4697	2.2%
2791	34741	35472	36184	36930	37635	38323	38968	39633	40352	41056	41736	42420	43104	43749	2.1%
2792															
2793															
2794	348.4	351.6	354.8	358.1	361.3	364.5	367.7	370.9	374.1	377.3	380.5	383.7	386.9	390.1	0.9%
2795	274.6	277.3	280.0	282.6	285.3	288.0	290.7	293.5	296.2	298.9	301.6	304.3	306.9	309.6	1.0%
2796	58.6	60.5	62.3	64.2	65.9	67.6	69.3	70.8	72.3	73.5	74.5	75.5	76.5	77.7	2.6%
2797	151.4	153.0	154.6	156.2	157.8	159.4	160.9	162.5	164.2	165.5	166.9	168.2	169.6	170.9	1.0%
2798	16.5	16.2	15.9	15.6	15.3	15.0	14.7	14.4	14.2	14.0	13.7	13.5	13.2	13.0	0.3%
2799															
2800															
2801	167.9	168.8	169.8	170.6	171.5	172.5	173.5	174.6	175.8	177.2	178.6	180.0	181.3	182.5	0.7%
2802	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.62	1.65	1.68	1.71	1.74	1.78	2.0%
2803	5.30	5.13	5.03	4.98	4.95	4.92	4.94	4.95	4.95	4.97	5.02	5.07	5.13	5.21	- -
2804															
2805															
2806															
2807	13922	14287	14671	15082	15456	15862	16252	16635	17064	17479	17887	18299	18729	19173	2.5%
2808	1.93	1.92	1.91	1.93	1.93	1.90	1.86	1.82	1.82	1.81	1.77	1.75	1.74	1.74	4.1%
2809	93.7	94.9	96.1	97.3	98.5	99.8	101.0	102.2	103.5	104.7	105.9	107.2	108.4	109.7	1.2%
2810	17.44	17.63	17.89	18.28	18.55	18.82	19.07	19.28	19.62	19.86	20.03	20.18	20.36	20.57	2.7%
2811															
2812															
2813															
2814															
2815															
2816															
2817															

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
cesbingbk.d100611a	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**

Sources: 2008 and 2009: IHS Global Insight, Global Insight Industry and Employment models, September 2010. Projections: U.S. Energy Information Administration, AEO2011 National Energy Modeling System run cesbingbk.d100611a.

21. National Impacts of Renewable or Clean Energy Standards (RPS/CES)

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Renewable or Clean Energy Standard														
RPS/CES Credits (billion kwh)														
Clean Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.69	13.39	13.39	13.39	13.39	13.39
Natural Gas	327.86	333.18	359.99	335.37	295.76	297.19	301.63	437.21	413.19	420.46	440.80	459.39	473.09	481.82
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.24	20.48	30.71	44.95	46.08
Conventional Hydropower	5.13	5.14	4.35	4.48	4.62	4.73	10.96	13.62	15.04	15.04	15.04	15.04	13.72	15.04
Geothermal	16.49	16.79	16.74	16.74	18.67	20.49	20.69	20.69	20.69	20.69	20.69	20.69	22.18	22.18
Municipal Waste	23.70	23.80	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79
Wood and Other Biomass	42.36	36.17	40.05	41.71	49.42	57.69	64.29	101.21	135.54	199.36	221.35	235.40	249.95	264.09
Dedicated Plants	40.48	34.51	38.25	39.97	41.85	44.40	44.59	53.97	55.05	57.49	60.35	64.66	71.45	78.33
Cofiring	1.88	1.66	1.81	1.74	7.57	13.29	19.69	47.24	80.48	141.87	161.00	170.74	178.50	185.76
Solar Thermal	0.97	1.03	1.13	1.22	1.59	2.30	2.48	2.49	2.49	2.50	2.51	2.51	2.52	2.53
Solar Photovoltaic	1.26	2.35	3.52	5.33	7.05	8.46	9.92	11.74	13.71	13.80	13.90	14.01	14.15	14.30
Wind	52.97	72.43	91.53	110.61	177.85	187.25	187.72	188.54	189.04	191.45	191.46	191.46	191.46	191.46
Total Earned	470.75	490.88	541.11	539.27	578.75	601.91	621.48	799.30	820.20	910.72	963.40	1006.41	1049.20	1074.68
Total Penalty	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Credit Bank Activity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	199.12	166.94	198.30	205.04	195.04	182.99	119.80
Cumulative Credit Bank Balance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	199.12	366.06	564.36	769.40	964.44	1147.44	1267.24
Baseline Electricity Sales (billion kwh)	**3712.12**	**3555.63**	**3729.86**	**3675.91**	**3725.23**	**3770.26**	**3783.11**	**3796.99**	**3814.10**	**3842.96**	**3875.31**	**3909.28**	**3941.22**	**3968.01**
RPS/CES Levels														
(percent of total sales)														
Credits Required	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.90	18.10	19.30	20.60	21.80	23.00	25.20
Credits Achieved	12.68	13.81	14.51	14.67	15.54	15.96	16.43	21.05	21.50	23.70	24.86	25.74	26.62	27.08
Credits Achieved With Bank	12.68	13.81	14.51	14.67	15.54	15.96	16.43	15.81	17.13	18.54	19.57	20.76	21.98	24.06

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2818															
2819															
2820															
2821															
2822															
2823															
2824															
2825															
2826															
2827															**2009-**
2828	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2035**
2829															
2830															
2831															
2832															
2833	13.39	16.90	16.90	16.90	16.90	19.80	24.88	31.29	39.61	52.08	74.43	104.82	150.36	215.92	- -
2834	501.84	517.64	529.06	537.75	547.27	559.45	571.85	574.16	598.48	640.62	677.73	726.75	763.39	835.41	3.6%
2835	46.41	58.31	75.41	95.81	118.62	144.71	174.75	209.29	248.90	294.48	346.91	406.99	427.18	488.56	- -
2836	15.29	26.30	26.41	26.41	26.41	26.41	26.41	26.46	26.46	26.46	26.46	26.14	26.14	23.10	6.0%
2837	22.18	23.89	25.86	28.12	30.44	33.09	36.15	39.67	42.58	44.89	46.24	47.06	48.18	49.13	4.2%
2838	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	23.79	0.0%
2839	274.92	283.16	293.28	303.43	308.86	315.84	316.08	312.00	303.20	292.49	278.37	281.67	295.29	295.08	8.4%
2840	87.58	96.71	106.27	115.84	123.14	130.44	134.36	134.85	134.77	135.74	136.52	137.39	138.42	139.22	5.5%
2841	187.34	186.45	187.00	187.60	185.73	185.40	181.72	177.15	168.43	156.75	141.85	144.29	156.87	155.86	19.1%
2842	2.54	2.55	2.55	2.56	2.57	2.58	2.59	2.59	2.60	2.61	2.62	2.64	2.65	2.66	3.7%
2843	14.46	14.63	14.84	15.06	15.30	15.58	15.89	16.23	16.59	16.89	17.18	17.49	17.82	20.78	8.7%
2844	191.46	203.53	217.19	232.91	250.34	268.09	291.06	316.03	340.26	347.15	347.20	347.24	347.28	351.00	6.3%
2845	1106.28	1170.70	1225.29	1282.74	1340.50	1409.33	1483.45	1551.53	1642.48	1741.47	1840.95	1984.58	2102.08	2305.44	6.1%
2846	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2847	50.75	23.06	-14.94	-44.86	-77.34	-99.43	-117.50	-125.73	-113.30	-108.32	-82.46	-43.90	-35.67	-19.66	- -
2848	1317.99	1341.05	1326.11	1281.25	1203.91	1104.49	986.99	861.26	747.96	639.64	557.17	513.28	477.61	457.95	- -
2849															
2850	**3996.71**	**4022.69**	**4050.51**	**4073.34**	**4094.47**	**4114.80**	**4134.53**	**4146.58**	**4164.96**	**4183.40**	**4201.43**	**4208.50**	**4215.72**	**4220.36**	**0.7%**
2851															
2852															
2853															
2854	27.40	29.60	31.80	34.00	36.20	38.40	40.60	42.80	45.00	47.20	49.40	51.60	53.69	55.90	- -
2855	27.68	29.10	30.25	31.49	32.74	34.25	35.88	37.42	39.44	41.63	43.82	47.15	49.86	54.63	5.4%
2856	26.41	28.53	30.62	32.59	34.63	36.67	38.72	40.45	42.16	44.22	45.78	48.19	50.70	55.09	5.5%

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**cesbingbk.d100611a**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2857	**(percent of baseline sales)**														
2858	Credits Required	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.90	18.10	19.30	20.60	21.80	23.00	25.20
2859	Credits Achieved	12.68	13.81	14.51	14.67	15.54	15.96	16.43	21.05	21.50	23.70	24.86	25.74	26.62	27.08
2860	Credits Achieved With Bank	12.68	13.81	14.51	14.67	15.54	15.96	16.43	15.81	17.13	18.54	19.57	20.75	21.98	24.06
2861															
2862	**RPS/CES Credit Prices**														
2863	**(2009 mills per kilowatthour)**														
2864	Credit Price	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.92	39.71	41.74	43.45	45.79	48.11	50.45
2865	Credit Cap	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2866															
2867	**RPS/CES Payments (billion 2009 dollars)**														
2868	**Annual**														
2869	Credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.31	32.57	38.02	41.86	46.08	50.48	54.22
2870	Penalty	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2871	**Total**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**30.31**	**32.57**	**38.02**	**41.86**	**46.08**	**50.48**	**54.22**
2872	**Cumulative**														
2873	Credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.31	62.88	100.90	142.75	188.83	239.31	293.53
2874	Penalty	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2875	**Total**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**30.31**	**62.88**	**100.90**	**142.75**	**188.83**	**239.31**	**293.53**
2876															
2877															
2878															
2879	kwh = Kilowatthours.														
2880	- - = Not applicable.														
2881	Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System run cesbingbk.d100611a.														

	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
1	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
2857															
2858	27.40	29.60	31.80	34.00	36.20	38.40	40.60	42.80	45.00	47.20	49.40	51.60	53.70	55.90	- -
2859	27.68	29.10	30.25	31.49	32.74	34.25	35.88	37.42	39.44	41.63	43.82	47.16	49.86	54.63	5.4%
2860	26.41	28.53	30.62	32.59	34.63	36.67	38.72	40.45	42.16	44.22	45.78	48.20	50.71	55.09	5.5%
2861															
2862															
2863															
2864	53.41	54.38	57.82	60.52	62.82	66.07	69.35	71.59	75.68	82.43	89.07	101.54	107.50	115.82	- -
2865	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2866															
2867															
2868															
2869	59.08	63.66	70.85	77.63	84.21	93.11	102.87	111.08	124.30	143.55	163.97	201.51	225.98	267.01	- -
2870	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2871	**59.08**	**63.66**	**70.85**	**77.63**	**84.21**	**93.11**	**102.87**	**111.08**	**124.30**	**143.55**	**163.97**	**201.51**	**225.98**	**267.01**	- -
2872															
2873	352.61	416.27	487.13	564.76	648.97	742.08	844.95	956.03	1080.33	1223.88	1387.85	1589.37	1815.34	2082.35	- -
2874	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
2875	**352.61**	**416.27**	**487.13**	**564.76**	**648.97**	**742.08**	**844.95**	**956.03**	**1080.33**	**1223.88**	**1387.85**	**1589.37**	**1815.34**	**2082.35**	- -
2876															
2877															
2878															
2879															
2880															
2881															

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, page 16. Please provide the STRATEGIST input and output files, in machine readable format, for each alternative option the Company evaluated.

RESPONSE

The Company is unable to provide the requested input and output files. Strategist is a proprietary utility planning application that is licensed solely by Ventyx Inc., which owns Strategist in its entirety. Kentucky Power contacted Ventyx Inc. and it confirmed that the application software, source code, database, and associated documentation, including input files, are its confidential and proprietary intellectual property. Access to the documentation may be granted solely by Ventyx Inc., at its own discretion, under a mutually binding Non-Disclosure Agreement. Access to the database and/or the application itself is granted only under exclusive license with Ventyx Inc. Ventyx does not allow access to the Strategist source code under any circumstances. Kentucky Power will assist the Sierra Club in contacting Ventyx, Inc. to obtain the required Non-Disclosure Agreement.

WITNESS: Scott C Weaver

SC EXHIBIT 28

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, Exhibits 1-4

a. Please provide all assumptions and workbooks, in electronic format with all calculations operational and formulae intact, used to prepare Exhibits SCW-1 through SCW-4, including output files from the Aurora model.

RESPONSE

Please see the response to KIUC Item No. 28, First Set.

WITNESS: Scott C Weaver

SC EXHIBIT 29

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that support, source, and/or otherwise address the assumptions used in the analyses presented by Mr. Weaver in his Direct Testimony. This includes, but is not limited to, any alternative assumptions that were considered but not used in the analyses.

RESPONSE

Please see KPSC 1-48 and the attachments to this response. Confidential protection is being sought for attachments 2 and 3.

WITNESS: Scott C Weaver

SC EXHIBIT 30

Kentucky Power Company

REQUEST

Refer to pages 11-12 of the Weaver Testimony, Table1. Provide the Strategist model runs for each option and a detailed discussion of the main assumptions and economic drivers for each option run.

RESPONSE

Spreadsheet files that extract results from the Strategist model output files can be found on page 2 of this response. These five (5) spreadsheets offer the individual model run results that are reflective of one of the primary economic driver in the analysis--long-term commodity prices including natural gas, coal, energy (on and off-peak), and emissions value, including CO2/carbon. Each spreadsheet reflects a discrete "pricing scenario" that was detailed--in totality--on Exhibit SCW-4, and for each of those individual pricing scenarios on Exhibit SCW-4A, 4B, 4C, 4D and 4E, Attachments 1 through 5, respectively. Within each spreadsheet, those unique prices were applied to each of the five (5) Big Sandy "disposition options" evaluated.

A discussion of this commodity pricing can be found on Table 3, pages 28 & 29 of Mr. Weaver's testimony, as well as a narrative description of these pricing assumptions and impacts, starting on page 27, line 1, through page 30, line 14.

Another critical/main assumption in these modeling runs was the assumption around the installed costs of the various Big Sandy disposition alternatives. Those costs are identified on Table 2, found on page 24 of Mr. Weaver's testimony. Further, beginning on page 20, line 4, through page 24, line 3, that testimony also offers an overview of the critical drivers impacting each of those 4 unique Big Sandy disposition options evaluated.

Lastly, Exhibit SCW-1, pages 10-14, offers a narrative of the "key risk factors" that were set forth as part of the stochastic (Monte Carlo) modeling exercise also performed to support the discrete Strategist results.

WITNESS: Scott C Weaver

SC EXHIBIT 31

Kentucky Power Company

REQUEST

Please clearly define and reconcile the major groups of capital costs used in the Strategist model with those described in witness testimony, e.g. costs of DFGD, costs of boiler modification, costs of life extensions, etc.

RESPONSE

The capital costs in Table 2 in Mr. Weaver's testimony were used as the basis for the capital costs of the four alternative options defined in the PROVIEW module of Strategist.

WITNESS: Scott C Weaver

SC EXHIBIT 32

Kentucky Power Company

REQUEST

Refer to the Company's response to Sierra Club initial data request 1-68, and the Direct Testimony of Scott Weaver page 47 line 15 through page 48 line 2 and SCW-5.

a. Please provide all inputs to the Aurora model, in machine readable format.

b. Please provide the distribution assumed for each of the six key risk factors considered by the Aurora model, in machine readable format.

c. Please provide the rationale supporting each of the distributions assumed for each of the six key risk factors.

RESPONSE

a. Please see attached files on accompanying CD.

b. Please see attached files on accompanying CD.

c. A normal distribution was assumed for all of the risk factors; commodity prices of all types are typically normally distributed.

WITNESS: Scott C Weaver

SC EXHIBIT 33

Kentucky Power Company

REQUEST

Refer to the Company's response to Sierra Club initial data request 1-69 and Exhibit SCW-5 regarding the use of Aurora to test the sensitivity of the Company's four options.

a. Please provide all inputs to the Aurora model in operational, electronic format.

b. Please provide all outputs from the Aurora model, by year, in operational, electronic format.

c. Please provide all inputs used to prepare Exhibit SCW-5, by year, in operational, electronic format.

d. Please provide all workpapers used to prepare Exhibit SCW-5 in operational, electronic format.

RESPONSE

a. See response to Sierra Club's 2-34a.

b. See accompanying CD for Excel files for part b. of this response.

c. & d. See accompanying CD for Excel files for parts c. & d. of this response.

WITNESS: Scott C Weaver

SC EXHIBIT 34

Kentucky Power Company

REQUEST

Refer to the Company's responses to Staff initial data requests 1-68 and 1-71, Sierra Club initial data request 1-47, and Attorney General initial data request 1-13 regarding the use of Aurora to develop projections of wholesale power prices.

a. Please provide all inputs to the Aurora model for that simulation in operational, electronic format.

b. Please provide all outputs from the Aurora model for that simulation, by year, in operational, electronic form.

RESPONSE

a&b. See attached files on accompanying CD.

WITNESS: Scott C Weaver

SC EXHIBIT 35

- .FSV files in final form evaluating Big Sandy in 5 commodity pricing scenarios
- contain inputs and outputs from 2040

Some changes we need to make
8.04 to -100 in 2014 to 2024

2nd No Carbon Option 4b

Option 1,2 ~~or~~ 3 stays at 8.04 from 2025 to 2037

constrained to not add capacity

can add capacity from 2025 to 2037

Low Band, Option 1
BS 2~~3~~, operating life 30 years
Alt, year, CCK2, min # to add in 2032 to (

fixed O+M spike - captured on-going capital for any unit that is retired, carried on through time until unit was retired and PV'ed them to the year of retirement
in essence accounting for end effects for that particular cost

no method of capturing annual year to year capital cost w/o CER other than fixed costs

drop in fixed cost - ongoing capital expenditures made earlier in the period are expiring b/c of the 15 year life

SC EXHIBIT 36

EXHIBIT ____

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVIENENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

Direct Testimony of
J. Richard Hornby
Including Revised – Supplemental Pages

On Behalf of
Sierra Club

May 1, 2012

SC EXHIBIT 37

Table of Contents

1. INTRODUCTION

Q. Please state your name and occupation.

A. My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues. Its primary focus is on electricity resource planning and regulation including computer modeling, service reliability, resource portfolios, financial and economic risks, transmission planning, renewable energy portfolio standards, energy efficiency, and ratemaking. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, environmental groups, U.S. Environmental Protection Agency, Department of Energy, Department of Justice, Federal Trade Commission and National Association of Regulatory Utility Commissioners. Synapse has over twenty professional staff with extensive experience in the electricity industry.

2. BACKGROUND

Q. Please summarize your educational background.

A. I have a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now the School of Engineering at Dalhousie University, and a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT).

Q. Please summarize your work experience.

A. I have over thirty years of experience in in the energy industry, primarily in utility regulation and energy policy. Since 1986, as a regulatory consultant I have provided expert testimony and litigation support on natural gas and electric utility resource planning, cost allocation and rate design issues in over 120 proceedings in the United States and Canada. During that period my clients have included utility regulators, consumer advocates, environmental groups, energy marketers, gas producers, and utilities. Prior to 1986 I served as Assistant Deputy Minister of Energy for Nova Scotia where I helped prepare the province's first comprehensive energy plan and served on a federal-provincial board responsible for regulating exploration and development of offshore oil and gas reserves. I have also spent several years as a project engineer in the industrial sector.

I was the lead author of *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky* (January 2012) and of projections of long-term avoided energy supply costs in New England prepared 2007, 2009 and 2011. I was co-author of *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers,* a 2006 report prepared for the National Association of Regulatory Utility Commissioners (NARUC).

My resume is attached to this testimony as Exhibit__(JRH-1).

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Have you testified previously before the Kentucky Public Service Commission (Commission)?

A. No, I have not.

3. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The Sierra Club retained the Synapse team of Dr. Jeremy Fisher, Ms. Rachel Williams and me to assist in their review of the Kentucky Power Company's (KPCo or Company) application for a Certificate of Public Convenience and Necessity (CPCN) to retrofit Big Sandy Unit 2.

The purpose of my testimony is to provide an overview of our analysis of whether the Company's proposed CPCN for Big Sandy Unit 2 and associated Environmental Cost Recovery (ECR) surcharge are reasonable and cost-effective for complying with the environmental requirements the Company is facing. My testimony discusses the resource options KPCo evaluated, the range of future scenarios it used to evaluate those resource options, its projection of revenue requirements for each resource option under those future scenarios and its conclusions regarding the merits of its proposed CPCN based upon its projections and analyses.

Synapse witness Wilson describes her review of the Company's modeling of resource options using Strategist as well as her use of Strategist to model those resource options under an additional future scenario reflecting a different projection of carbon prices. Synapse witness Dr. Fisher describes his review of the Company's assumptions regarding the costs of certain resource options, certain future scenarios the Company tested in its Strategist modeling and the Company's modeling of those resource options using Aurora.

Q. What data sources did you rely upon to prepare your review of the Company's request?

A. My review relies primarily upon the direct testimonies and Exhibits of KPCo witnesses Wohnhas, Weaver and Munsey and their responses to various data requests. The specific responses I cite in this testimony are attached as Exhibit____(JRH-10). In addition I reviewed KRS 278.183, referred to as the Environmental Surcharge Statute, as well as materials regarding Kentucky's energy and environmental policies and regarding strategies that companies with coal units are using to comply with environmental regulations.

4. SUMMARY CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize KPCo's request for a CPCN to install environmental control equipment on Big Sandy Unit 2 and for a rate increase to recover the costs of that investment.

A. KPCo has requested approval for a CPCN to install environmental control equipment, primarily a Dry Flue Gas Desulfurization System ("DFGD"), on Big Sandy Unit 2 ("the Plant"). Concurrently it has requested an increase in its ECR surcharge in order to recover the cost of installing that equipment. The Company estimates the environmental control equipment, at a capital cost of $940 million, will have an annual revenue requirement of approximately $178 million and cause its retail rates to increase by more than 30 percent.

KPCo maintains that installing a DFGD on that Unit is in the long-term best interest of its customers. The Company's conclusion is based upon the results of Mr. Weaver's economic evaluation which indicates that, relative to the three other resource options it examined, retrofitting Big Sandy Unit 2 is the best option for complying with the environmental regulations the Company is facing.

Q. Please summarize your major conclusions and recommendation regarding the Company's request.

A. My first conclusion is that the Company has not demonstrated that its proposed CPCN for Big Sandy Unit 2 is reasonable and cost-effective for complying with the environmental requirements the Company is facing. That conclusion is based upon the results of our review which indicates that the Company has not evaluated the full range of resource options available to it, that its projections of revenue requirements for the resource options it did evaluate are not correct, that its evaluation of future scenarios does not include a reasonable projection of carbon prices and that its Monte Carlo risk analysis is flawed. My second, related, conclusion is that allowing KPCo to recover the costs of installing environmental control equipment on Big Sandy Unit 2 from ratepayers will not result in reasonable rates.

Based upon those two conclusions I recommend that the Commission not approve the Company's request for a CPCN for Big Sandy Unit 2.

Q. Please summarize your conclusions and recommendations regarding ratemaking should the Commission decide to approve the CPCN.

A. In the event that the Commission decides to approve the Company's request for a CPCN, I am sure it will limit the Company's recovery of actual costs to only the amounts it finds just and reasonable. My understanding of the ratemaking process under the Environmental Surcharge Statute is that the Commission will review the Company's actual costs every six months, and disallow actual amounts it finds that are not just and reasonable, and that it will shift recovery of amounts it does find reasonable from the surcharge into base rates every two years. However, my conclusion is that even with those measures, ratepayers will still bear the bulk of the financial risk resulting from

KPCo's decision to propose and pursue the CPCN since they will be paying the vast majority of, if not all, the revenue requirements resulting from KPCo's choice of that resource option.

Based on that conclusion, if the Commission decides to approve the CPCN, I recommend that the Commission require the Company to:

- recover its investment in environmental controls at Big Sandy Unit 2 based upon a depreciation rate consistent with generally accepted accounting principles, which would be a period of at least twenty years;
- modify its System Sales Clause to be consistent with the amount of off-system sales margin it assumed would flow to ratepayers under its modeling of the CPCN option; and
- bear the risk of carbon regulation costs in excess of the values the Company has assumed in its early carbon future scenario.

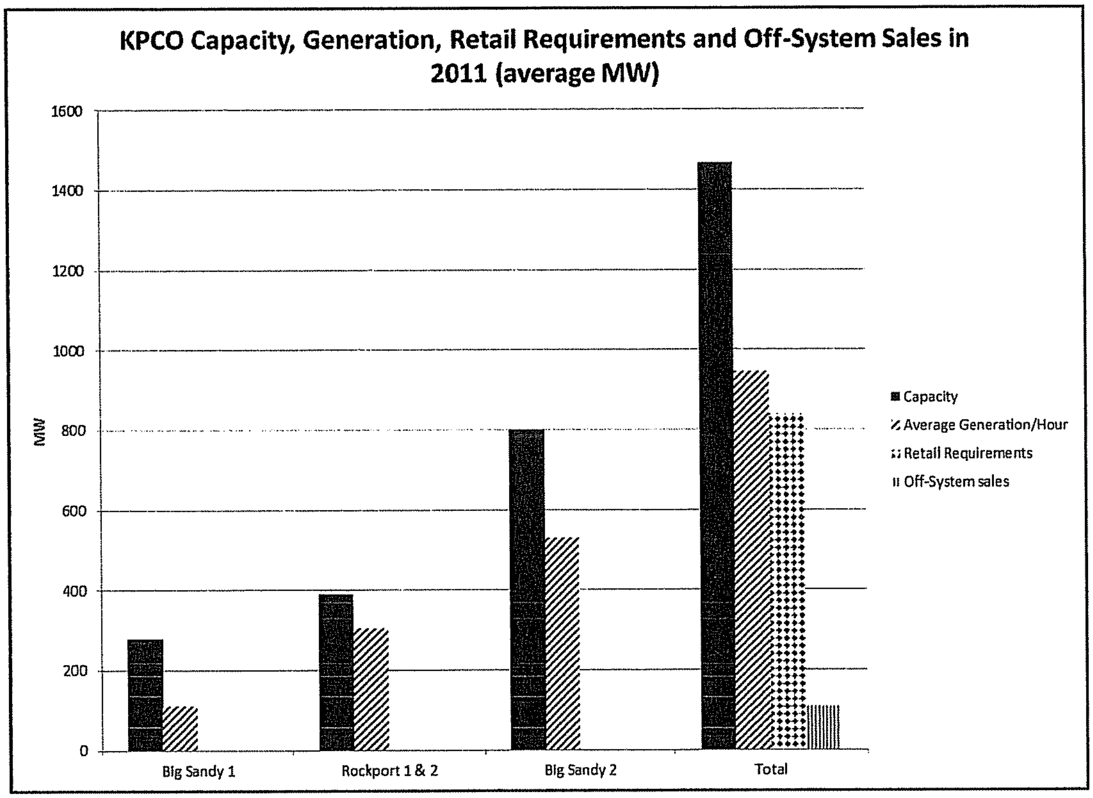
5. APPROACH TO REVIEW OF KPCO REQUEST

Q. Please summarize KPCo's current mix of capacity and energy by resource.

A. KPCo has modeled its future operations as if it will be operating as a stand-alone company rather than a member of the current AEP pool. As a stand-alone company KPCo is currently entirely dependent on coal units for capacity and annual generation, i.e., energy, to serve its retail load. It owns two coal fired units, Big Sandy Unit 1 and Big Sandy Unit 2. It acquires capacity and energy from two other coal-fired units, Rockport 1 and Rockport 2, through a long-term purchase power agreement which its modeling assumes will be renewed to continue through 2040

KPCo's mix of capacity and energy in 2011, as modeled by the Company in Strategist, is illustrated in the bar chart below from Exhibit___(JRH-2). In that year Big Sandy Unit 2 accounted for approximately 55% of the Company's total capacity and generation. In contrast, Big Sandy Unit 1 accounted for approximately 20% of the Company's capacity but provided only 12% of its annual energy. That Exhibit also indicates that the Company used approximately 10% of its total generation to make off-system sales. Under the

KPCo System Sales Clause, Tariff S.S.C., the Company retains forty percent of the margin revenue from off-system and credits retail customers with the remaining sixty percent.



Q. Please summarize KPCo's current resource mix and the known and emerging environmental regulations it is facing.

A. The Company is currently facing the following known and emerging environmental regulations: the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standard, the Coal Combustion residuals rule, the Clean Water Act "316(b)" rule and expected Effluent Limitation Guidelines as well as the New Source Review consent decree. The Company expects that Big Sandy Unit1 and Big Sandy Unit 2 will need to comply with at least some of these environmental requirements by 2016.

Q. Please summarize the economic evaluation KPCo conducted to evaluate its resource options for complying with those environmental requirements.

A. According to Mr. Weaver's direct testimony, KPCo evaluated its resource options for complying with these environmental requirements in four major steps.

- First, it identified four resource options for complying with these environmental requirements.
- Second, it identified a Base Case and four additional discrete scenarios to evaluate the future conditions under which those resource options might operate.
- Third, the Company developed projections of the revenue requirements associated with each resource options over a 30-year period, 2011 to 2040, under each of the five discrete future scenarios. The Company developed those projections using the Strategist model, a computer simulation model, and a separate workbook to calculate the carrying charges of each resource option.
- Fourth, the Company used Aurora, another computer simulation model, to prepare a risk analysis of the four resource options.

Based upon his review of the revenue requirements of each resource option under each of the five scenarios, summarized in his Exhibit___(SCW-4), his review of the results from the Aurora model and other points in his direct testimony, Mr. Weaver concluded that retrofitting Big Sandy 2 with DFGD technology is in the long-term best interest of KPCo's customers.

Q. Please describe the approach the Synapse team used to determine if the Company's proposed CPCN for Big Sandy Unit 2 and associated ECR surcharge were reasonable and cost-effective for complying with the environmental requirements the Company is facing.

A. The Synapse team treated the Company's application as a request for rate relief and reviewed that request in the same level of detail as a base rate filing. Specifically we reviewed the validity of the key input assumptions underlying the Company's projection of revenue requirements for each resource option under each future scenario. Where applicable we also verified the mathematical accuracy of those revenue requirement projections.

We followed this rate-making proceeding approach based on the Commission's Order in Case No. 2011-00161 indicating that a proceeding under the Environmental Surcharge Statute is a rate-making alternative to a general rate case. Our approach is also based upon the Environmental Surcharge Statute requirement that the Commission must determine if the Company's proposed plan and rate surcharge are reasonable and cost-effective for complying with the environmental requirements it is facing.

Q. Please contrast the magnitude of rate relief the Company is requesting in this proceeding with the rate relief it requested in its most recent general rate proceeding.

A. The increase in rates the Company is requesting in this proceeding is much larger than the increase it requested in its most recent general rate proceeding. In this proceeding the Company is requesting an increase in annual revenues of $178.8 million, or over 30 percent. That amount is approximately fifty percent more than the increase of $123.6 million it requested in its 2009 general rate proceeding, Case No. 2009-00459, and approximately three times greater than the $63.7 million increase it ultimately agreed to in the settlement of that Case.

Q. Is it more difficult to assess the reasonableness of its request in this proceeding than its request in a general rate proceeding?

A. Yes. In order to determine the reasonableness of the revenue requirements a utility requests in any type of rate proceeding parties generally follow two basic steps. They review the Company's support for the input values it has used to calculate its revenue requirements and they review the mathematical accuracy of its calculation of revenue requirements based upon those input values. While I do not wish to minimize the time and effort that parties put into verifying the reasonableness of the revenue requirements in general rate proceedings, I consider it more difficult to execute those two steps in this type of rate proceeding. In a general rate case in Kentucky, parties review a projection of revenue requirements for a historical test year, thus many of the inputs are actual or close to actual costs, and the costs are limited to one year. In contrast, in this proceeding the parties must verify the Company's support for assumptions for 30 years as well as the mathematical accuracy of its calculations using those assumptions.

Given the uncertainty associated with the values of key input assumptions over that planning horizon it is particularly important that all parties have a clear understanding of the basis for the Company's key input assumptions regarding resource costs and of the range of future market and regulatory conditions it may face. It is particularly important to "stress test" those assumptions under a range of realistic possible future scenarios.

6. ASSESSMENT OF KPCO REQUEST FOR CPCN AND RATE INCREASE

Q. Has your team been able to confirm the validity of all key input assumptions and verify the Company's calculations and projections based upon those inputs?

A. No. Our review has found many aspects of the Company's filing unclear, particularly in terms of documentation of key input assumptions and transparency of calculations based upon those assumptions. Ms. Wilson and Dr. Fisher discuss the lack of clarity and inconsistencies in various aspects of the Company filing. As a result we do not claim to have confirmed the validity of all key input assumptions underlying the Company's projection of revenue requirements for each resource option under each future scenario, or to have verified the mathematical accuracy of all of its projections.

Q. Please list the major problems the Synapse team has found with the Company's economic evaluation

A. Our review has identified problems with four major aspects of the Company's economic evaluation. The four major problem areas are:

i. the limited range of pre-determined resource options the Company modeled in Strategist;

ii. certain of the Company's assumptions regarding the costs of the four resource options it did evaluate were unreasonable or inconsistent, and when corrected change the projected revenue requirements of those Options;

iii. the limited range of future scenarios the Company modeled using Strategist to evaluate the four resource options, in particular its failure to evaluate scenarios that are substantively different from each other or a scenario with a reasonable projection of carbon prices; and

iv. the risk analysis the Company prepared using Aurora.

i. Limited Range of Pre-determined Resource Options

Q. Please summarize the four resource options the Company evaluated for complying with known and emerging environmental regulations at the Big Sandy plant.

A. For Big Sandy Unit 1 the Company's proposed environmental compliance strategy is to retire it as a coal-fired unit effective January 1, 2015. For Big Sandy Unit 2, the Company decided to choose among four possible resource options in order to determine the best environmental compliance strategy. The four resource options it evaluated were:

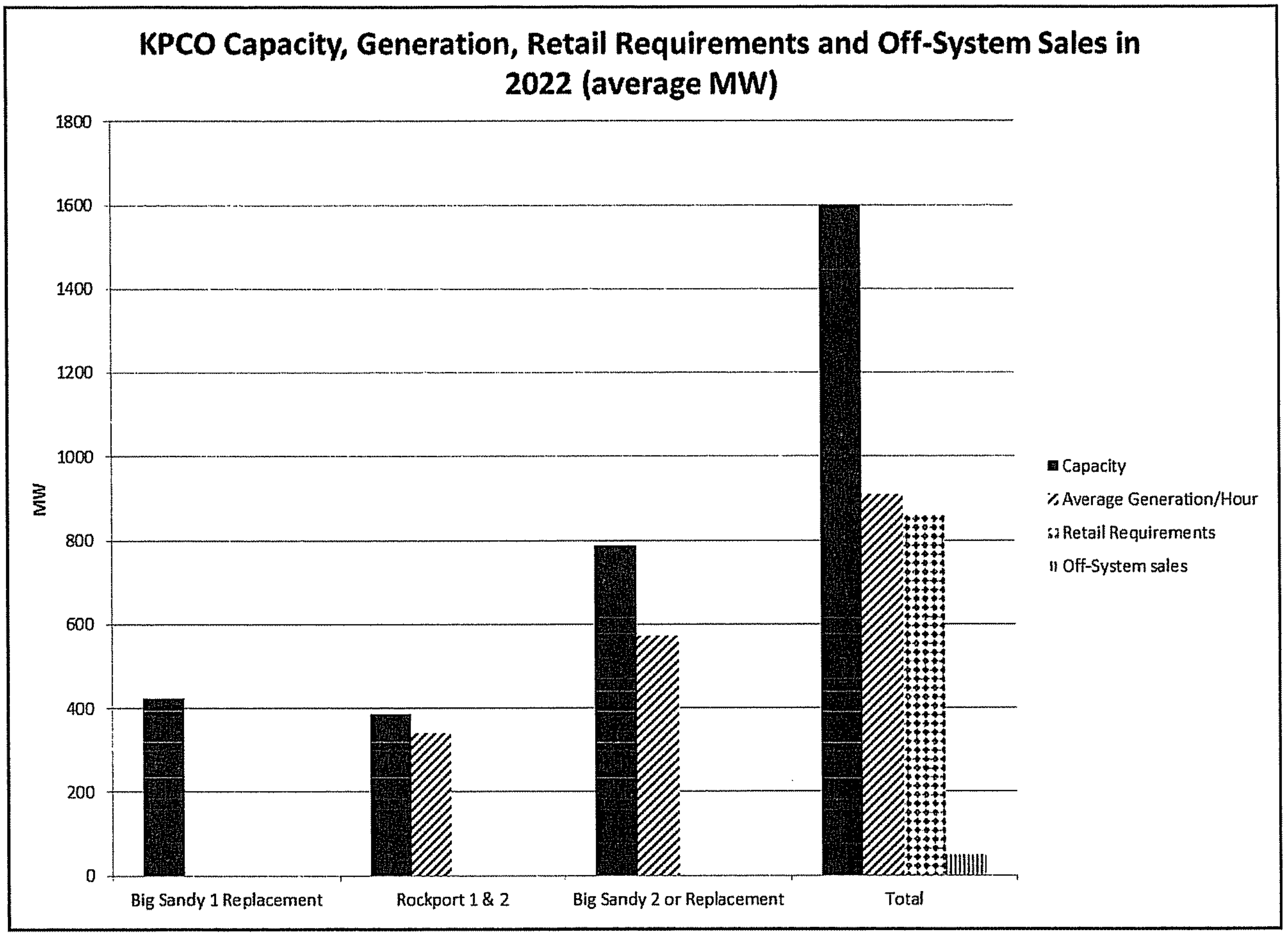
- Option 1, Retrofit Big Sandy Unit 2 with DFGD by June 2016 in order to allow it to continue operating at approximately 800 MW;
- Option 2, Retire Big Sandy Unit 2. Build a 762 MW natural gas-fired combined cycle unit (CC) by January 2016 at the Big Sandy plant site;
- Option 3, Retire Big Sandy Unit 2. Repower Big Sandy Unit 1 as a 745 MW natural gas-fired combined cycle unit (CC) by January 2016;
- Option 4, Retire Big Sandy Unit 2 and replace essentially all of its capacity and energy with purchases from the relevant PJM wholesale markets for a period of either 5 years (Option 4A) or 10 years (Option 4B) and then build or acquire replacement CC capacity.

Q. Please comment on the Company's choice of those four options.

A. I have three concerns with the Company's choice of those four options. First, it has not provided a formal analysis supporting its choice of those four options (Response to KIUC 1-29).

Second, the Company has in effect limited its evaluation to three resources, to be acquired in 2016 in "all or nothing" quantities under either full ownership or full procurement. Specifically KPCO has evaluated a single large coal unit ownership option, a single large natural gas CC ownership option (i.e., Options 2 and Option 3 are essentially the same) and an all market purchase option. The bar chart below, from Exhibit___(JRH-3), illustrates the extent to which the Company would be dependent on whichever of those single large resource options it implemented during the period 2017 through 2024. Using 2022 as a representative year, the bar chart indicates that Big Sandy

Unit 2 (Option 1), or its replacement, would account for approximately 49% of the Company's total capacity and approximately 63% of its annual energy.



Third, the Company's assessment of only four options is inconsistent with the wide range of FGD designs it evaluated (Exhibit SCW-3).

Q. Do those four options represent all of major resource options available to KPCo?

A. No. The Company did not evaluate all of the major resource options available to it. First, the Company did not explore a portfolio approach consisting of one or more alternative mixes of various types and sizes of resources, including renewable sources, energy efficiency or demand response (Responses to Sierra Club 1-52, Sierra Club 1-62). Second, KPCo did not evaluate a variation on Option 4 under which it would acquire capacity and energy through a strategy consisting of purchases from the PJM wholesale markets, long-term power purchase agreements and other hedging strategies. (That approach would address the concerns the Mr. Weaver raises regarding the Company's exposure to cost uncertainty and price volatility variation under Option 4). Another approach that KPCo evaluated in its March 2011 analyses but not in this proceeding was a combination of a smaller gas CC, perhaps in the 600 MW range, plus market purchases (Response to Sierra Club 1-69). The Company maintains that Option 2 represents a proxy for the bids it would receive in response to a Request for Qualifications (RFQ) or a Request for Proposal (RFP) to buy existing gas-fired CC or CT units (Responses to Staff 1-65 and 2-29). However, the Company did not evaluate a "resource blind" RFP for capacity and energy to identify the full range of fossil, renewable and efficiency resources available to replace Big Sandy Unit 2, including fractional ownership (Responses to Sierra Club 1-51 and 2-21).

Q. Did the Company have the ability to evaluate a much wider range of resource options?

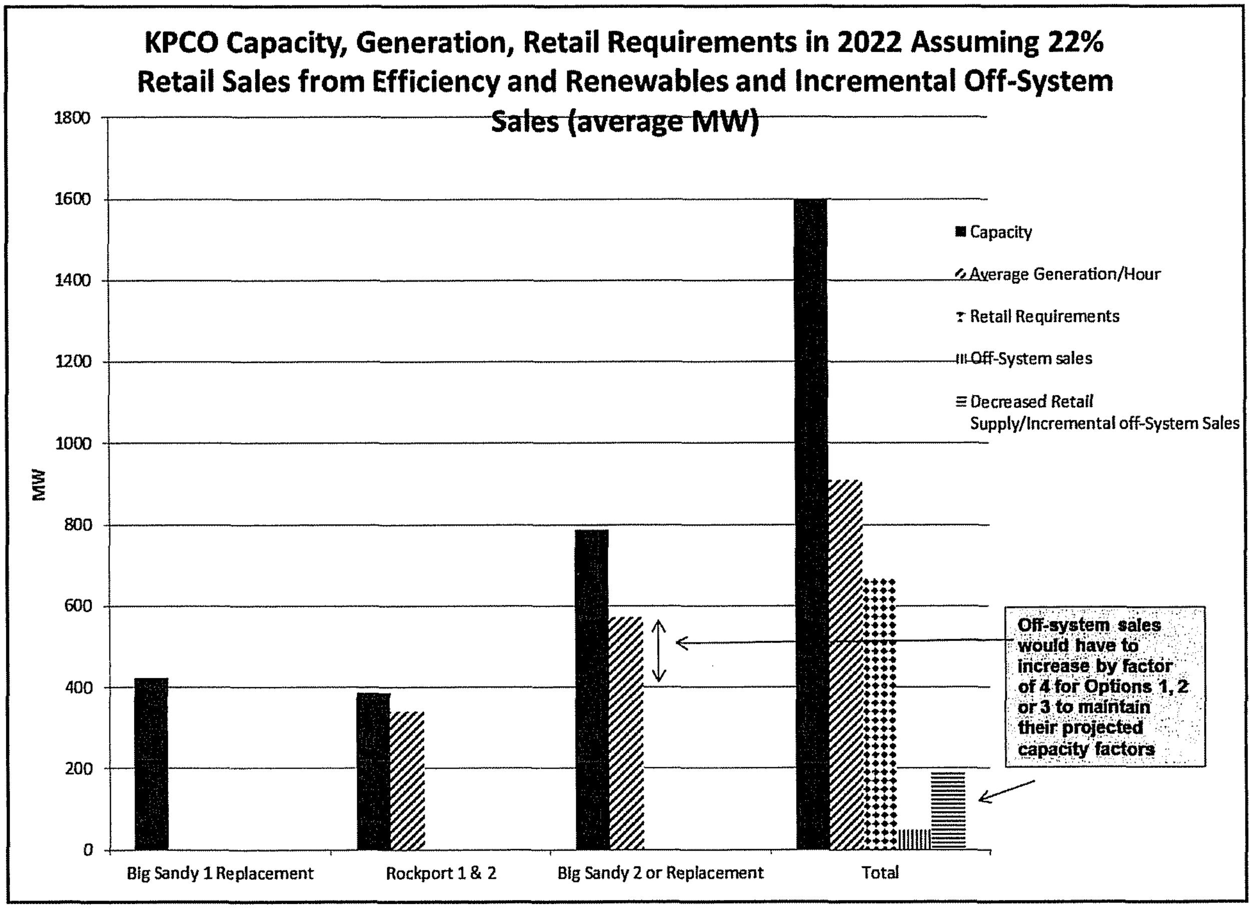
A. Yes. The Company could have used Strategist, its primary modeling tool, to evaluate a much broader range of supply-side and demand-side resource options. As Ms. Wilson explains, the Company had the ability to enter a broad range of available options into Strategist and to let the model choose the portfolio with the optimal, i.e., least-cost, mix of capacity and energy from that inventory of resource options.

Q. Why is it so important for the Company to have evaluated a range of resource options?

A. It is important for the Company to have evaluated a range of resource options given the magnitude of investment under consideration and the long-term risk associated with making such a large investment in one resource. As I noted earlier, there are significant uncertainties regarding how the future will unfold over the next ten years, let alone through 2040. There is tremendous value in maintaining some degree of flexibility to respond to changes in future regulatory and market conditions, and thus ensuring rates can remain reasonable as circumstances change. It is important to ensure that KPCo is not committing itself to a major investment in baseload capacity which it may not need to meet retail load in ten years or fifteen years due to major changes in the requirements of its retail customers, the relative costs of the resources available to it or future environmental regulations. Thus, it is essential that the Company demonstrate that it has thoroughly evaluated the resource portfolios which might provide it that flexibility.

Q. Can you provide a simple illustration of one change in market conditions the Company may face?

A. Yes. Legislation being introduced in the Kentucky General Assembly proposes to establish a Renewable and Energy Efficiency Portfolio Standard (REPS) for utilities in the states. Under that proposal, utilities would have to meet their retail load with increasing specific quantities of efficiency and renewables, reaching approximately 22% of their retail load by 2022. That change in energy requirements for retail load is illustrated in the bar chart in Exhibit___(JRH-4), using 2022 as the same representative year as in the bar chart from Exhibit___(JRH-3) shown earlier.



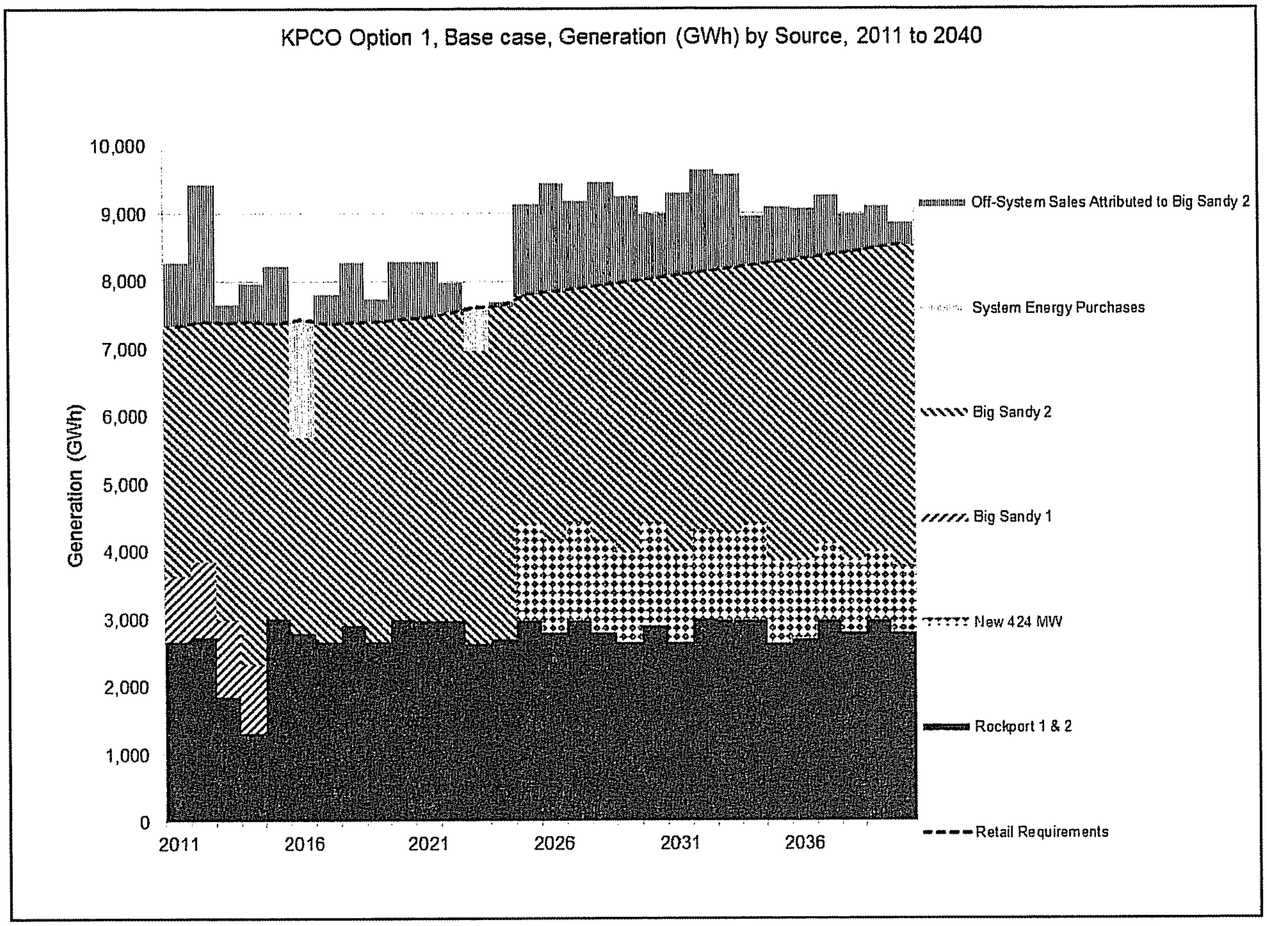
This simple illustration indicates that if KPCO implemented either of Options 1, 2 or 3 and its actual retail requirements from fossil generation in 2022 proved to be over twenty per cent less than it has modeled in this proceeding, it might not have the most cost-effective mix of capacity and energy. For example, it might have too much baseload capacity and not enough peaking capacity. Admittedly this simple, one-year snapshot does not reflect the potential the Company might have to not renew its power purchase agreement for one of its Rockport units, or to defer its proposed addition of 407MW of capacity in 2025. However, it does illustrate the type of substantial change in conditions the Company may face over a planning horizon through 2022, let alone through 2040.

Q. Does the Company's evaluation of the four resource options it considered include a thorough analysis of the flexibility it will have to respond to changes in market conditions under each of the resource options?

A. No. First, the Company has not evaluated its four resource options under a future scenario with much lower retail requirements from fossil generation (Response to Sierra Club 1 – 43 and 2-25). Second, Mr. Weaver refers to the importance of planning flexibility, adaptability to risk and other planning criteria on page 7 of his testimony. However he does not provide any metrics for those criteria nor any assessments beyond those presented in his Exhibits SCW 4 and SCW 5 (Responses to Sierra Club 1-33, 1-34, 1-57, 2-22 and 2-31). Finally, as I discuss later in my testimony, KPCo has not tested its four resource options against a sufficiently broad range of future scenarios.

Q. Please describe the Company's projected mix of capacity and energy under the Base Case if Option 1 is approved.

A. If Option 1 is approved, the Company will continue to be largely, if not entirely, dependent on coal units for its capacity and energy through 2040. KPCo's projected mix of capacity and energy under the Base Case if Option 1 is approved is illustrated in the chart below from Exhibit___(JRH-5). That Exhibit also indicates that the Company projects it will continue to use generation from Big Sandy Unit 2 to make off-system sales in addition to supplying its retail customers.



ii. Resource Option Cost Assumptions and Resulting Revenue Requirements

Q. Please summarize the Company's projection of revenue requirements for each resource option under each future scenario.

A. The Company's projection of revenue requirements for each resource option is the sum of six major categories of projected costs. Those six categories of costs are:

i. Fuel and other variable production costs of all KPCo units, which include its entitlement share of Rockport Units 1 and 2;

ii. Emission allowance costs of all KPCo units;

iii. Sales or purchases of market energy by or for KPCo;

iv. Sales or purchases of market capacity by or for KPCo;

v. Fixed operation and maintenance (FOM) costs for all KPCo units; and

vi. Fixed carrying charges of major incremental KPCo capital investments in generation capacity.

The largest two categories of costs are variable production costs, in particular fuel, and fixed carrying charges.

Q. Please summarize the models the Company used to calculate these revenue requirements.

A. The Company used the Strategist model to project the first five categories of cost inputs to its revenue requirements, which I refer to as Net Production and FOM costs. It used only the economic dispatch and production costing functionality of the Strategist model to project theses costs. Strategist develops those projections based on the numerous inputs entered by the Company including projections of retail load, generating unit heat rates, fuel prices, emission prices, and capacity and energy prices in PJM wholesale markets.

The Company used a separate, spreadsheet model to project the fixed carrying charges and costs of capacity purchases associated with each resource option. Finally KPCo used a Strategist Compilation Workbook to calculate the revenue requirements of each resource option, i.e., to essentially add the Net Production and FOM costs from Strategist to the fixed carrying charges and purchased capacity costs.

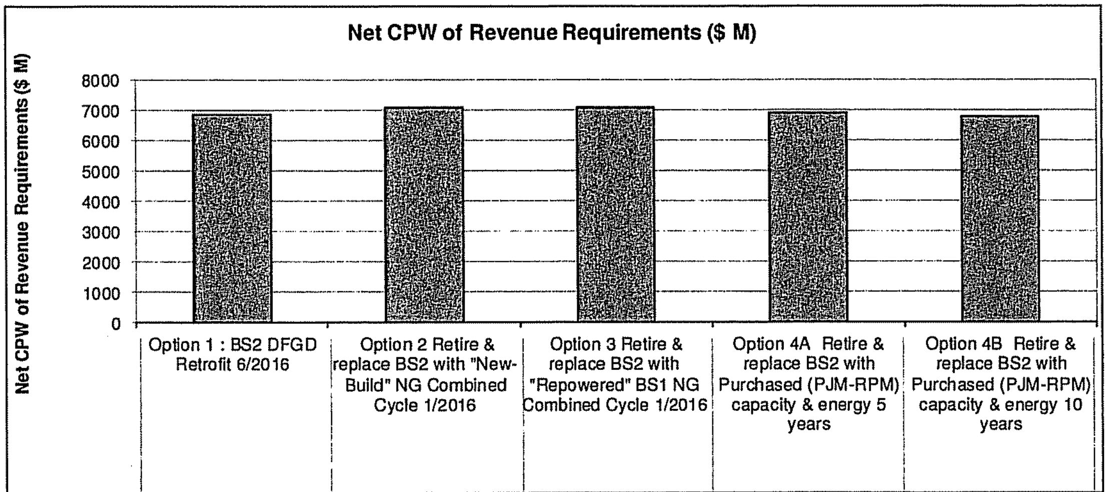
Q. Did your team review the Company's estimate of net production and FOM costs using Strategist?

A. Yes. Ms. Wilson began her review by obtaining the Company's inputs to Strategist for each of its 25 runs and using Strategist to independently reproduce and verify the Company projections for each of those runs. Ms. Wilson's testimony describes the problems she found with the Company's projections of net production and FOM costs using Strategist.

Q. Please summarize the Company's projected revenue requirements for each of the resource options and future scenarios it considered.

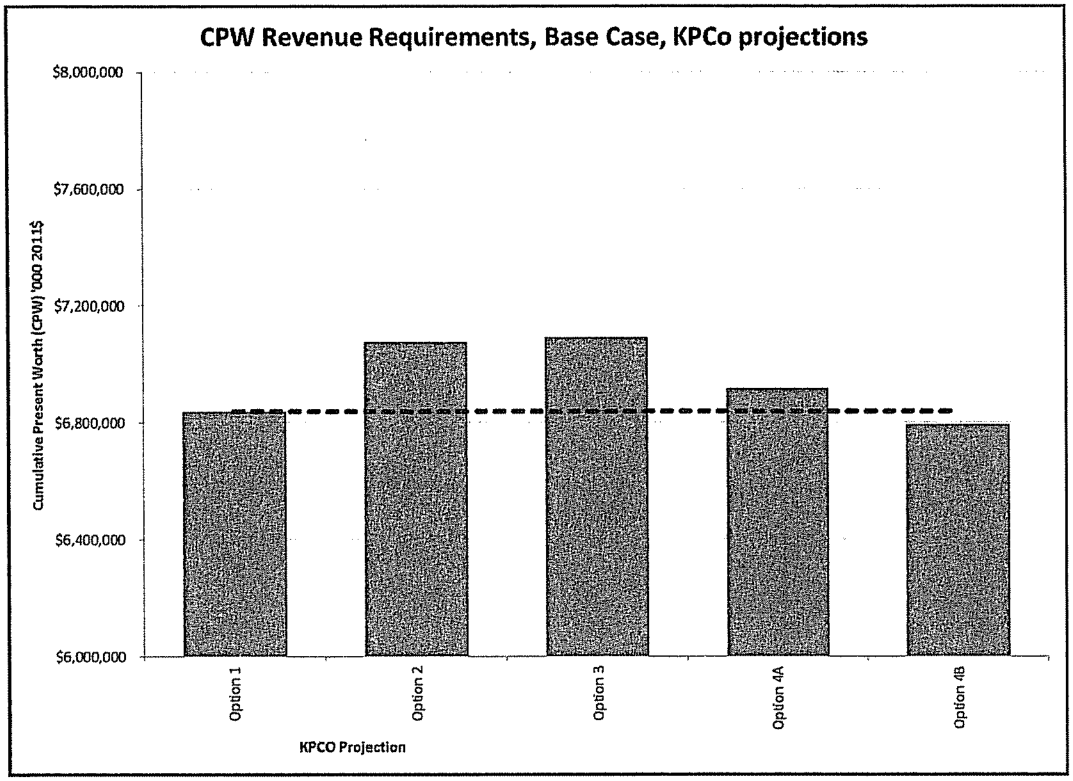
A. The cumulative present worth (CPW) values of the Company's projected revenue requirements for each resource option and future scenario, assuming a 15 year depreciation period for Option 1, are presented in Exhibit___ (JRH-6). That Exhibit also presents the difference in CPW by resource option, measured relative to Option 1, for each future scenario, in absolute and percentage terms.

The CPW of total revenue requirements for each resource option under the Base Case are very close, as indicated in the bar chart below taken from Exhibit___ (JRH-6).



Net CPW of Revenue Requirements ($ M)	$ 6,839	$ 7,075	$ 7,091	$ 6,918	$ 6,792
Delta of Net CPW from Option 1 ($ M)	N/A	$236	$252	$79	-$47
Delta of Net CPW from Option 1 (%)	N/A	3.5%	3.7%	1.2%	-0.7%

The fact that the CPWs of the resource options are relatively close may not be surprising, given the thirty year timeframe and the inclusion of costs common to all four resource options, i.e., the Rockport units and the 407 MW CC scheduled to be added in 2025. However, it does require one to focus on the differences in CPW by resource option for each future scenario as well as on other policy considerations in order to determine which resource option is cost-effective and reasonable. The differences in the CPW of total revenue requirements for each resource option under the Base Case are more apparent in the bar chart below, also taken from Exhibit___ (JRH-6).

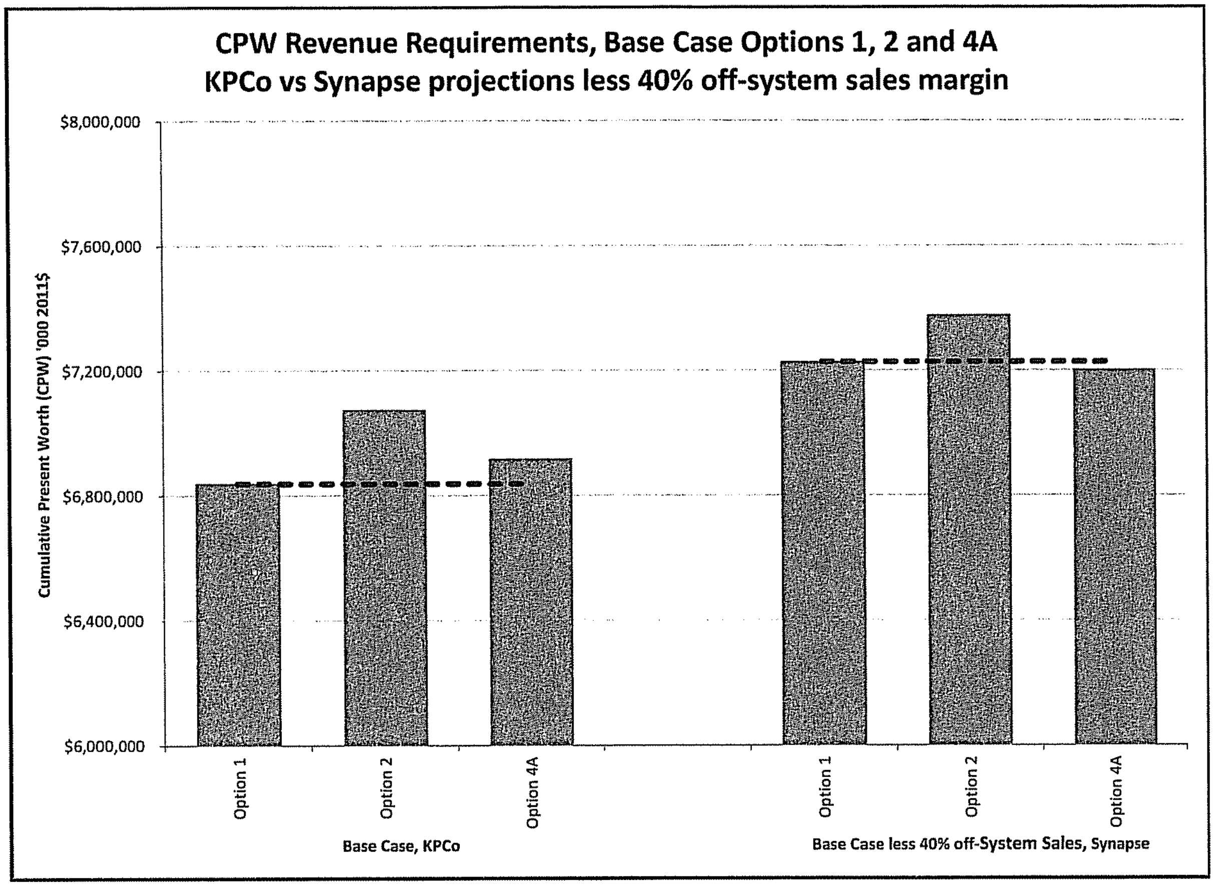


In the balance of my testimony, I use the Company's projections for Option 1, Option 2 and Option 4A under its Base Case to illustrate the problems we have found with its projections.

Q. Please comment on the Company's treatment of margin from off-system sales in its projection of revenue requirements for each resource option.

A. As discussed in more detail by Dr. Fisher, the Company appears to have credited 100% of the margin from projected off-system sales against the projected gross revenue requirements of each resource option when calculating net revenue requirements to be recovered from retail customers. We support this treatment, but note that it is not consistent with the Company's current System Sales Clause, under which KPCo shareholders retain 40% of margin from off-system sales.

If the Company's projection of revenue requirements reflected a continuation of the current System Sales Clause, and credited only 60% of the margin from off-system sales against gross revenue requirements, the difference in CPW between Option 1 and the other three Options is reduced substantially. Dr. Fisher quantifies that impact, which is illustrated in the bar chart from Exhibit ___(JRH-7) revised.


CPW Revenue Requirements, Base Case Options 1, 2 and 4A
KPCo vs Synapse projections less 40% off-system sales margin
$8,000,000
$7,600,000
$7,200,000
$6,800,000
$6,400,000
$6,000,000
Cumulative Present Worth (CPW) '000 2011$
Option 1
Option 2
Option 4A
Option 1
Option 2
Option 4A
Base Case, KPCo
Base Case less 40% off-System Sales, Synapse

Q. [redacted]

[redacted]

iii. Limited Range of Future Scenarios without Reasonable Projection of Carbon Prices

Q. Please summarize the five future scenarios the Company modeled in Strategist in order to evaluate the four resource options it considered.

A. The Company evaluated its four resource options under a Base Case and four discrete sensitivity scenarios. The five future scenarios it modeled are:

1. Base Fleet Transition-CSAPR. This assumes natural gas prices at Henry Hub reach \$6.52/MMBtu by 2020 and a carbon price starting at \$15 per metric tonne in 2022, both in nominal dollars. The carbon price is based on assumption that carbon emissions from existing fossil generation will begin to be regulated in that year.
2. Fleet Transition-CSAPR: Higher Band. This tests sensitivity to higher prices for natural gas and coal, relative to Base Case levels, with no other change to Base Case assumptions.

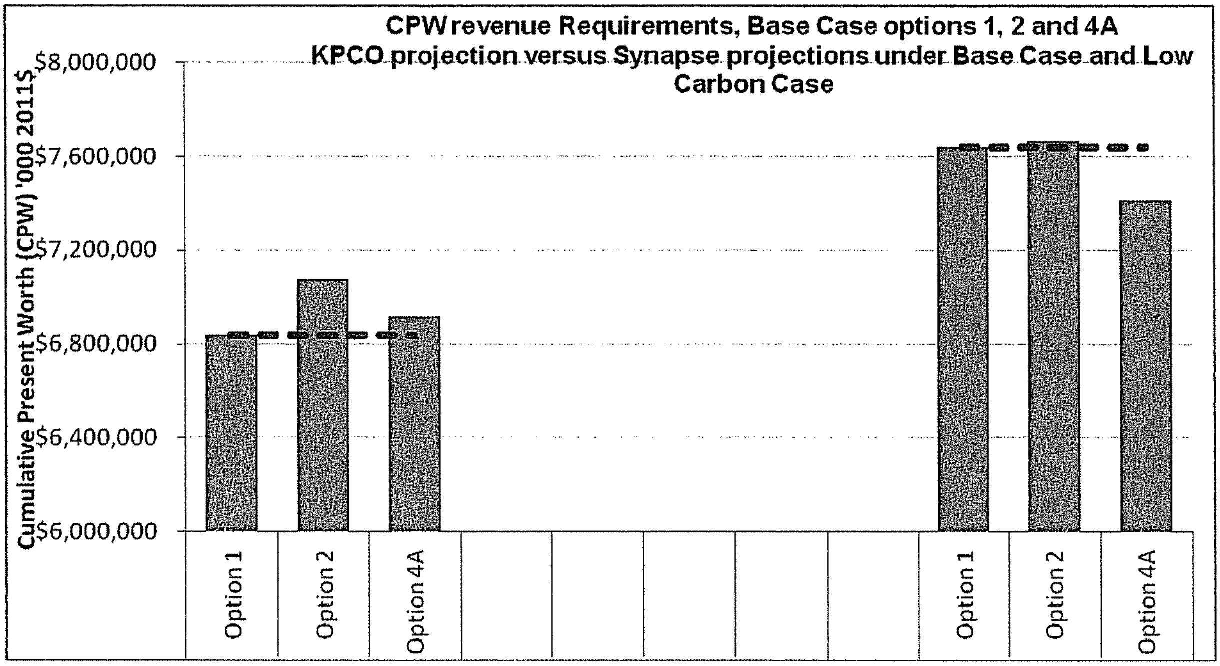
3. Fleet Transition-CSAPR: Lower Band. This tests sensitivity to lower prices for natural gas and coal, relative to Base Case levels with no other change to Base Case assumptions.
4. Fleet Transition-CSAPR: No Carbon. This tests sensitivity to zero prices for carbon, with no other change to Base Case assumptions.
5. Fleet Transition-CSAPR Early Carbon. This tests sensitivity to prices for carbon starting at $15 per metric tonne in 2017, with no other change to Base Case assumptions.

Q. Has your team identified problems with any of the Company's assumptions for those five future scenarios?

A. Yes. Dr. Fisher's review indicates that the Company's assumption of carbon prices under its Base Case and each of its four other scenario are too low, including those in the Early Carbon scenario. In addition, his analysis indicates that the Company's assumptions regarding the relationship between natural gas and coal prices in its higher band and lower band scenarios are inconsistent with its assumption regarding the correlation of those prices in its Aurora runs. Also, as noted earlier, the Company did not test a scenario with a much lower level of retail requirements from fossil generation.

Q. Have you prepared revised projections of revenue requirements using corrected assumptions for Options 1, 2 and 3 and a future scenario with a reasonable projection of carbon prices?

A. Yes. Exhibit ___(JRH-9 Supplemental) presents projections of revised revenue requirements using corrected assumptions for options 1, 2 and 3 under the carbon scenario recommended by Dr. Fisher. Those revised projections indicate that Option 1 has the highest revenue requirement, and as such is not reasonable or cost-effective.



iv. Risk Analysis Using Aurora

Q. Please summarize why and how the Company used the Aurora model.

A. As discussed, the Company used Strategist to quantify the risk associated with each resource option by testing the sensitivity of their projected revenue requirements under its Base Case to four discrete changes in assumptions about the future, i.e., higher fuel prices, lower fuel prices, higher carbon prices and zero carbon prices. The Company used the Aurora model in an attempt to further quantify the potential risks associated with each resource option by projecting their revenue requirements under 100 different future scenarios. The Aurora model created the 100 different futures based on the Company's input assumptions regarding the relationships, or correlations, between five key input assumptions using a "Monte Carlo" modeling technique or algorithm. The 100 futures reflect different combinations of five key input assumptions, i.e., coal prices, natural gas prices, carbon prices, wholesale power prices and retail demand.

Q. In theory, does this type of modeling have the potential to provide useful information for resource planning decisions?

A. Yes. For example, *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*, a 2006 report that Synapse prepared for the NARUC, notes the potential benefit of using computer models such as Aurora to analyze long-term risks of alternative portfolios of resources.

Q. Does the Company's application of the Aurora model in this proceeding provide a useful assessment of the cost risk associated with each resource option?

A. No. Dr. Fisher identifies numerous problems with the Company's risk modeling using the Aurora model. Given the extent of the problems he has identified, the results from the Company's risk modeling using the Aurora model do not provide a useful assessment of the cost risk associated with each resource option.

v. Sharing of Financial Risk between Ratepayers and Shareholders

Q. Will ratepayers bear the majority of the financial risk under any resource strategy that the Company ultimately implements?

A. Yes. Ratepayers bear the majority of the financial risk under any resource strategy the Company ultimately implements because their rates are based upon the revenue requirements that result from that strategy.

Consider the allocation of financial risk under the following hypothetical. The Commission decides to approve Big Sandy Unit 2 with a 15 year depreciation and by 2030 the scenario Mr. Wohnhas discusses in his testimony proves to be correct, i.e., future increased EPA standards cause operation of Big Sandy Unit 2 not to be economically feasible. Under that hypothetical KPCo would retire Big Sandy Unit 2 in 2030 and replace it with some other source of capacity and energy. Under this hypothetical the Company would have recovered its full investment in Big Sandy Unit 2, including a return on equity, by 2030 and will bear no financial risk. In contrast, ratepayers will bear all the financial risk. They will have paid the revenue requirements associated with Big Sandy Unit 2 through 2030, which was approved on the assumption it was the most cost-effective option through 2040, plus they will have to pay the revenue requirements associated with the replacement capacity and energy from 2030 to 2040.

Q. Please comment on the financial risks that the Company should bear if the Commission decides to approve KPCo's request for a CPCN

A. In the event that the Commission decides to approve the Company's request for a CPCN, ratepayers will bear the vast majority of the financial risk resulting from KPCo's decision to propose and pursue that option. Since the Company apparently believes this is the best approach, it is reasonable to expect them to bear a reasonable portion of the risk associated with this investment. The Company's only rationale for fifteen 15 year depreciation appears to be to avoid exposure to absorbing any stranded investment in the Big Sandy Unit 2 DFGD (Responses to Sierra Club 2-16 and 2-18). According to generally accepted accounting principles, an investment such as this should be depreciated over its useful life (Response to Sierra Club 1-17). For the DFGD this is twenty to thirty years according to the Company's witnesses and projections.

The Company's projection of revenue requirements for the CPCN option assumes a significant amount of off-system sales margins will flow to ratepayers. It is reasonable for the Commission to hold the Company to those projections. Thus, the Company should be required to modify its System Sales Clause to be consistent with the off-system sales margins it has assumed would flow to ratepayers under its modeling of the CPCN option.

Finally, the Company asserts that it has tested its four resource options against a realistic range of carbon prices. Again, since the Company apparently believes it has evaluated the full range of these prices, it is reasonable to expect them to bear the risk of carbon regulation costs that prove to be higher than the values the Company has assumed in its projections.

7. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize the major conclusions and recommendation from your review of the Company's request.

A. My first conclusion is that the Company has not demonstrated that its proposed CPCN for Big Sandy Unit 2 is reasonable and cost-effective for complying with the environmental requirements the Company is facing. That conclusion is based upon the results of our review, which indicates that the Company has not evaluated the full range of resource options available to it, that its projections of revenue requirements for the resource options it did evaluate are not correct, that its evaluation of future scenarios does not include a reasonable projection of carbon prices and that its Monte Carlo risk analysis is flawed. My second, related, conclusion is that allowing KPCo to recover the costs of installing environmental control equipment on Big Sandy Unit 2 from ratepayers will not result in reasonable rates.

Based upon those conclusions my recommendation is that the Commission not approve the Company's request for a CPCN for Big Sandy Unit 2.

Q. Please summarize your conclusions and recommendation regarding ratemaking in the event the Commission decides to approve the Company's request.

A. In the event that the Commission decides to approve the Company's request for a CPCN, I am sure it will limit the Company's recovery of actual costs to only the amounts it finds just and reasonable. My understanding of the ratemaking process under the Environmental Surcharge Statute is that the Commission will review the Company's actual costs every six months, and disallow actual amounts it finds that are not just and reasonable, and that it will shift recovery of amounts it does find reasonable from the surcharge into base rates every two years. However, my conclusion is that even with those measures, ratepayers will still bear the bulk of the financial risk resulting from KPCo's decision to propose and pursue the CPCN.

Based on that conclusion, I recommend that the Commission require the Company to:

- recover its investment in environmental controls at Big Sandy Unit 2 based upon a depreciation rate consistent with generally accepted accounting principles, which would be a period of at least twenty years;
- modify its System Sales Clause to be consistent with the off-system sales margins the Company assumed would flow to ratepayers under its modeling of the CPCN option; and
- bear the risk of carbon regulation costs in excess of the values the Company has assumed in its early carbon future scenario.

Q. Does this complete your Direct Testimony?

A. Yes.

REVISED - SUPPLEMENTAL

LIST OF EXHIBITS

Exhibit__(JRH-9)
Supplemental