Date September 14, 2012

Company	CI/LI/CPP/Program Number	Version
Ohio Power	000021257	1

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	JCF 9-14-12		JCF 9-14-12

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
1	D. Lynch	9/17/12	
	L. L. Dieck		
	C. Zebula		
	B. X. Tierney		
	M. Heyeck		
	B. D. Radous		
	S. Burge		
	L.J. Weber		
	M. C. McCullough		
	D. E. Welch		
	R. P. Powers		
	L. Barton		
	Buckeye Power Approval		
	N. K. Akins		
2	Jenifer Fischer - 28th floor Ext 3032		
		9-25-12	Approved in PeopleSoft
		Sep 2012	Month Included in Board Package

Alternate CP&B Contacts:
Cathy Warchal - 28th Floor - Ext 1347

Scanned File Name: OPCo 000021257.pdf

Capital Improvement Approval Requisition

Company: Ohio Power Company **Version** 1

Project : **000021257 - Mitchell Unit 1 Electrostatic Precipitator Upgrade**
Moundsville, WV

Description: This CI requests funds for improvements to the Mitchell Unit 1 Electrostatic Precipitator (ESP) in order to meet environmental requirements and minimize the impact of flyash carryover on the Flue Gas Desulfurization (FGD) chemistry. In the Mercury and Air Toxics Standards (MATS) regime starting in 2015, the units will be required to demonstrate compliance with each of the limits (mercury (Hg), particulate matter (PM), and sulfur dioxide (SO_2)) on a more frequent basis.

The scope of this project includes:

- Replace Alstom high frequency transformer rectifier (T/R) sets
- Upgrade the voltage controls on 128 T/R sets with new digital controls

This project is included in the budget for 2013 and will be completed during the Spring outage.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$ -	$ 5,417,027	$ 5,417,027

Cash Flow:

	Prior Years	2012	2013	Future Years	Total
Capital	$ -	$ 1,029,077	$ 4,387,950	$ -	$ 5,417,027
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ -	$ 1,029,077	$ 4,387,950	$ -	$ 5,417,027
Associated O&M	$ -	$ -	$ 250,000	$ -	$ 250,000

Start Date: 9/1/2012 **Completion Date:** 8/31/2013 **In Service Date:** 4/14/2013

Regulatory Cost Recovery:

Ohio Power Company – Generation - $5.4M (100%)

- $5.2M (96%) Upon approval from State and Federal regulatory authorities, Ohio Power Company's generation fleet will transition into a competitive market. Currently, base generation revenues authorized by the PUCO (approved in March 2009 ESP) are not cost-of-service based, so there is no incremental cost recovery mechanism for new capital investments. As such, new investment carrying costs are deemed a cost of business offsetting ESP authorized revenues.
- $0.2M (4%) Allocated to WPCo and recovered in current demand charge effective 1/1/10.

Funding: **2012 Control Budget** *(included in IRC Presentation)* Yes **Offset Source** N/A

Requested future year funds are included in the last official Forecast.

Approved By: S. Burge/P. Vegas **Approved On:** 9/10/2012

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	-	-	-
This Submission	5,417,027	-	5,417,027
Total	**$ 5,417,027**	**$ -**	**$ 5,417,027**

2012 Direct Cost Budget Funding			Budget Offset Source and Amount
In Budget	$	1,080,000	
Budget Offset	$	-	

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	SVP, Business Unit	Burge, S.	See electronic approval attached	9/10/2012
amt ≤ $ 10m	Opco President	Vegas, P.	See electronic approval attached	9/10/2012
amt ≤ $ 20m	EVP & COO/EVP	McCullough, M.		
CP&B Review	Manager, Capital and Lease Improvements	Lynch, D.	D Lynch	9/17/12

Project Contacts

Contact	Name	Telephone
Project Manager	Kristopher Coombs	200-3342
Requisition Detail Provider	Daniel Connor	200-3019

Capital Improvement Approval Requisition

Project Justification

It is necessary to maintain the Electrostatic Precipitators (ESP) in safe, effective working order in order to meet environmental requirements and minimize the impact of flyash carryover on the Flue Gas Desulfurization (FGD) chemistry. Considerable maintenance on the ESP has been deferred in recent years due to uncertainty over the need to install a fabric filter. We now have evidence that a fabric filter will not be required in order to meet ongoing requirements, and it is appropriate to perform work necessary to ensure the safe and effective operation of the primary particulate control device. In the Mercury and Air Toxics Standards (MATS) regime starting in 2015, the units will be required to demonstrate compliance with each of the limits (Hg, PM, and SO_2) on a more frequent basis. The PM limit will need to be demonstrated either on a continuous basis with a PM CEMS or quarterly through a Method 5 PM test. The scope outlined below will allow the plant to perform diagnostic work and make changes to the operation of the ESP while the unit is online. The benefits for each of the proposed improvements are outlined below.

The Alstom high frequency T/R sets have been highly unreliable since their installation at Mitchell and 6 of 32 are currently out of service. Replacing the Alstom SIRs will allow the plant to have more reliable T/R's thereby decreasing O&M cost. The out-of-service Alstom T/R sets are creating empty spaces in the ESP that does not contribute to any collection of particulate. Replacement of the Alstom T/R's will save the Mitchell plant an estimated $125,000 per year. Upgrading from the factory installed AVCs to the MVC4 controls is necessary due to the fact that the existing controls are more than 30 years old. Replacement parts are hard to find which has made it difficult for the plant to service the controls. Furthermore, within the next few years, the controls will become obsolete, and finding parts will not be possible. The upgrades also will provide for more reliable and accurate control of the T/R sets, improved monitoring and troubleshooting capabilities. With enhanced controls and monitoring, it is expected that the EFOR on the unit will be reduced by 0.5 ppts. Engineering Services predicts a $100,000 per year reduction in O&M expenses after the AVCs have been upgraded. These upgrades will also help to avoid a 50 MW curtailment due to staying within the Hg limit put forth from the MATS ruling that will start in 2015.

Other Alternatives Considered

The "do nothing" case was not selected as it was determined that operational issues needed to be addressed.
A full rebuild of the ESP was also considered. This was ruled out as not cost effective. The proposed improvements will provide the necessary safety and performance improvements at minimal cost.

Conclusion

In order to ensure reliable performance of the ESP, and enhance personnel safety, it is recommended to implement the above improvements. A decrease in EFOR of as much as 0.5 ppts, a decrease in O&M expense of $250,000 per year, and an avoidance of a 50 MW curtailment is projected.

Associated/Future Projects

Upgrade ESP rapping system – approximately $5,000,000
Install new hoppers and hopper heaters – approximately $15,000,000

Generation CI/LI Approval Routing Document

Status: Approved

Last populated: 11/09/2005 12:29 PM

Plant	Unit	Funding Project #	Rev. #	Project Type
Mitchell	1	ML1SCO002	0	Project

Project Title: TR Set Replacement Program

Brief Description of Project (sufficient to determine that the project is Capital not O&M)

Replacement of PCB filled T/R sets with new non PCB sets and high frequency T/R sets Controls for for coventional T/R sets wil be upgraded as will rapper controls and communications Identical work was performed on Unit 2 in 2005

Company	LEG-9 #	Originated
Ohio Power Co	No	10/27/2005
Originator	**Project Manager**	**CI Approval Required by**
Jason A Horn	Jason A Horn	11/11/2005
Originator Phone No.	**Project Manager Phone No.**	**Amount to be Authorized**
8-200-1589 614-716-1589	8-200-1589 614-716-1589	$8,811,000 00

Approved by PMRG Board: Yes

Date Approved by PMRG Board: 06/13/2005

Will material become obsolete as a result of this CI? No

If you have questions concerning Obsolete Material, please contact your Supply Chain Representative.

Revised Budget (Direct Costs)	Prior Years	YR1 2005 ($x000)	YR2 2006 ($x000)	YR3 2007 ($x000)	YR4 2008 ($x000)	YR5+ 2009 ($x000)	Total
Additions - Plant	$0	$0	$6,030	$0	$0	$0	$6,030
Additions - ES	$0	$32	$0	$0	$0	$0	$32
Removal - Plant	$0	$0	$0	$0	$0	$0	$0
Removal - ES	$0	$0	$0	$0	$0	$0	$0
Total Direct Budget	$0	$32	$6,030	$0	$0	$0	$6,062
Associated O&M	$0	$0	$1,330	$0	$0	$0	$1,330
Project / CPP / Program Amount Being Authorized							
Additions - Plant	$0	$0	$6,987	$0	$0	$0	$6,987
Additions - ES	$0	$0	$450	$0	$0	$0	$450
Removal - Plant	$0	$0	$0	$0	$0	$0	$0
Removal - ES	$0	$0	$0	$0	$0	$0	$0
Total Direct Costs to be Authorized	$0	$0	$7,437	$0	$0	$0	$7,437
Overheads	$0	$0	$1,191	$0	$0	$0	$1,191
AFUDC	$0	$0	$183	$0	$0	$0	$183
Amount Being Authorized	$0	$0	$8,811	$0	$0	$0	$8,811
Associated O&M	$0	$0	$1,400	$0	$0	$0	$1,400

Ownership Unit Breakdown

Company	Funding #	Prior ($x000)	YR1 ($x000)	YR2 ($x000)	YR3 ($x000)	YR4 ($x000)	YR5+ ($x000)	Total ($x000)
Ohio Power - Gen	ML1SCO002	$0	$0	$8,811	$0	$0	$0	$8,811

Michael W Rencheck (on behalf of Mark A Gray, Vice President)	11/11/2005 12:55 PM EST
John M McManus	11/11/2005 02:07 PM EST
William L Sigmon	11/16/2005 04:20 PM EST

Comments

Michael J Simmons - 11/10/2005 09:28:12 AM
The PMRG Board members approved the ML Unit 2 TR Set Replacement project as well as similar work scope for Unit 1 contingent on off-sets being identified

Clyde L Pries - 11/16/2005 10:05:05 AM
2006 offsetting funds have been identified

Attachments

ML1sco002 PMRG Approvanewl xls

Capital Improvement Requesition Presented to the PMRG Board

8-Nov-05

Mitchell 1 T/R Set Replacement

Unit	Mitchell 1	Funding Numbers	ML1SCO002		Date / Project Mgr.	
Category Code	Safety	Operating Company (s)	Ohio Power Co.	-	Unit Role	Base
Project Description	Replacement of PCB filled T/R sets with new non PCB sets and high frequency T/R sets Controls for for coventional T/R sets wil be upgraded as will rapper controls and communications Identical work was performed on Unit 2 in 2005					
Project Plan	Unit 1 has 2 boxes, with 112 PCB filled T/R sets. The will be replaced with 96 new conventional non PCB filled T/R sets, 32 High frequency 70kV, 800mA T/R sets requires addition of two 575V to 480V transformers to operate available SIR's] [NOTE: Changing from 112 sets to 128 sets will not require internal sectionalization 16 sections are currently jumpered to others and will be restored to original sectionalization through this proces] Cabinet controls for the installed T/R sets will be upgraded along with rapper controls and communications. Key interlock system will also be replaced.					
Schedule	Outage starts April 2006 and ends June 2006					
Project Justification	■ Improved particulate collection from more power in the box ■ Improved safety and environmental compliance with removing PCB T/R sets ■ Improved safety with new key interlocks and fire detection systems ■ Replace underated power cable and other components ■ Replace deteriorating cable tray on roof and some vertical portions ■ Upgrad T/R set controls and rapper controls to provide better communication and overall performance in the boxes ■ 10,000 6-minute opacity exceedences since 1995 and $2 1 Million in lost generation due to opacity and other ESP related curtailments between 1997 and 2004 at Mitchell ■ Increase current density in the boxes from 58 mA/1000ft^2 closer to the fleet average of 80 mA/1000ft^2					
Alternatives Considered						

Financial Analysis Summary	10 Year IRR	10 Year NPV	Simple Payback (Years)	Discount Rate
	N/A	N/A	N/A	N/A
Economic Analysis Assumptions	**Availability Improvement**	**Capacity Improvement**	**Fuel Efficiency**	**Cost Reduction / Avoided Cost Savings**
	N/A	N/A	N/A	N/A

	Year	2005	2006	2007	2008	2009	Total ($)
Cash Flow (Requested) Direct Costs	**Amount Budgeted**	$32,000	$6,030,000				$6,062,000
	Material		$4,213,000				$4,213,000
	Labor		$2,774,000				$2,774,000
	Other		$450,000				$450,000
	Removal						$0
	Total Direct	$0	$7,437,000	$0	$0	$0	$7,437,000
	Delta in Budget vs Request	$32,000	($1,407,000)	$0	$0	$0	($1,375,000)
Loaded Costs	**Amount to be Authorized**		$8,811,000				$8,811,000
	Associated O&M		$1,400,000				$1,400,000

Additional Notes:

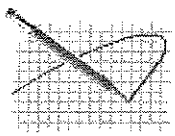
This is an environmental and safety related project and as such, the typical cost/benefit analysis is not warranted
Plant has budgeted $6.03 Million. $6 987 Million of plant directs is required ($957,000 variance)
None of these figures include the $450,000 FODA charges

Approved by the PMRG Board _____

Funding Project Estimates - Annual

Project Number	ML1SCO002	Construct	8,811,000	Retirements	0	Credits	0
Revision	1	Expense	0	Net RWIP	0	Jobbing	0
Budget Version	Conversion						

Expenditure Type	Charge Type	Budget Plant Class	Department	ls	Total Estimate	2002 Actuals	2002 Remaining	2003	2004
Additions	CI AFUDC		18110887 - Kammer F		183,000	0	0	0	
Additions	CI F/H Overheads		18110887 - Kammer F		447,000	0	0	0	
Additions	CI F/H Overheads		18110887 - Kammer F		744,000	0	0	0	
Additions	CI/LI All Other		18110887 - Kammer F		450,000	0	0	0	
Additions	CI/LI Labor		18110887 - Kammer F		362,000	0	0	0	
Additions	CI/LI Labor		18110887 - Kammer F		2,412,000	0	0	0	
Additions	CI/LI Materials		18110887 - Kammer F		201,000	0	0	0	
Additions	CI/LI Materials		18110887 - Kammer F		4,012,000	0	0	0	
Expense	CI Removal Cost		18110887 - Kammer F		1,400,000	0	0	0	



CI - LI Routing
Sent by: William L Sigmon

11/16/2005 04:20 PM

Please respond to
CI - LI Routing

To Kevin E Walker/AEPIN@AEPIN, John F Torpey/OR4/AEPIN@AEPIN, Patricia D Bachman/OR4/AEPIN@AEPIN, Paula L
cc
bcc
Subject CI / LI Approval Routing #ML1SCO002 has been Approved.

CI / LI Approval Routing #ML1SCO002 (TR Set Replacement Program) is approved and available for review at your convenience.

To review or act upon the request, please follow this link. ->>

Monthly Report of Improvement Requisitions
Approved for
Ohio Power Company
January 2006

	Number	Date Approved	Approved By	Description	Previously Approved	Amount To Be Authorized	Total
CI	X00000043-2006	12/20/05	English	Transmission: Various Locations - 2006 Asset Improvement Blanket (See Additional Information, page 19)	$0	$7,585,000	$7,585,000
CI	X00000657-2006	12/20/05	English	Transmission: Various Locations - 2006 Asset Improvement T-driven D Projects Blanket (See Additional Information, page 20)	$0	$18,000	$18,000
CI	000007354	12/20/05	Powers	Generation: Cardinal Unit 1 - Electrostatic Precipitator (ESP) Plenum Replacement (See Additional Information, page 61)	$0	$10,050,000	$10,050,000
CI	000009803	12/22/05	Morris	Generation: Cardinal and Mitchell Plants - Gypsum and Wastewater/Cake Overland Conveying System (See Additional Information, page 62)	$8,705,000	$1,565,000	$10,270,000
CI	000009913	01/04/06	Sigmon	Generation: Cardinal Unit 1 - Compressed Air Package	$633,000	$320,000	$953,000
CI	000010779	01/04/06	Sigmon	Generation: Gavin Plant - Trona System Completion (See Additional Information, page 63)	$872,000	$9,125,000	$9,997,000
CI	GV1CI9032	12/06/05	Sigmon	Generation: Gavin Unit 1 - Replacement of Rotating Blades	$0	$845,000	$845,000
CI	GV1CI9033	12/06/05	Sigmon	Generation: Gavin Unit 1 - Replacement of Stationary Blades (See Additional Information, page 64)	$0	$1,411,000	$1,411,000
CI	GV2CI9116	12/08/05	Sigmon	Generation: Gavin Unit 2 - Purchase Rockport Rotor (See Additional Information, page 65)	$0	$2,628,000	$2,628,000
CI	ML1SCO002	11/28/05	Sigmon	Generation: Mitchell Unit 1 - Transformer Rectifier (TR) Set Replacement (See Additional Information, page 66)	$0	$8,811,000	$8,811,000
CI	MLU1SAIRH	12/20/05	Sigmon	Generation: Mitchell Unit 1 - Air Heater Basket Replacement (See Additional Information, page 67)	$0	$1,809,000	$1,809,000
CI	X00000004-2006	01/03/06	Powers	Generation: Various Locations - 2006 Production Plant Blanket (See Additional Information, page 3)	$0	$44,768,000	$44,768,000
CI	X00000659-2006	01/03/06	Powers	Generation: Cook Coal Terminal - 2006 Mine Plant Blanket (Capital)	$0	$100,000	$100,000

Note: Requested current year amounts are in the approved budget or offsets have been made from other projects. Requested future year amounts are included in the Strategic Plan.

Date November 23, 2005

Company	CI/LI/CPP Number
Ohio Power	ML1SCO002

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PC 11-23-2005		PC 11-23-2005

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Torpey		
2	R. E. Munczinski	[signature] 11/28/05	
	S. Smith		
	S. Tomasky		
	B. Bond (SWEPCO T&D)		
	M. Heyeck		
	V. McCellon-Allen		
	M. K. Nazar		
	S. N. Smith		
	R. P. Powers		
	H. Koeppel		
	T. M. Hagan		
	J. Hamrock		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
	M. G. Morris		
3	P. L. Cahill - 28th floor Ext 2494		
		12-5-2005	Approved in PowerPlant
			Month Included in Board Package

Bachman - 28th Floor - Ext 2888 Bobby
Myers 28th Floor - Ext 2642

Expedited Approval Requested	Yes

Date September 5, 2006

Company	CI/LI/CPP/Program Number	Version
Ohio Power	ML2SCO004	

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PC 9-5-2006		PC 9-5-2006

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Torpey		
2	R. E. Munczinski	9/5/06	
	S. Smith		
	S. Tomasky		
	B. Bond (SWEPCO T&D)		
	M. Heyeck		
	V. McCellon-Allen		
	M. K. Nazar		
	S. N. Smith		
	R. P. Powers		
	H. Koeppel		
	T. M. Hagan		
	J. Hamrock		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
	M. G. Morris		
3	Paula Cahill - 28th floor Ext 2494		
		9-6-06	Approved in PeopleSoft
			Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Pat Bachman - 28th Floor - Ext 2888

AEP Printing Services:

Scanned File Name: Ohio Power ML2SCO004 Version .pdf

Please return to Capital Budgeting, 28th Floor 1RP

Generation CI/LI Approval Routing Document

Status: Approved

Last populated: 08/18/2006 10:40 AM

Plant	Unit	Funding Project #	Ver. #	Project Type
Mitchell	2	ML2SCO004	2	Project

Project Title: ML2-S-PRECIPITATOR TR SET REPL

Outage Code: (if necessary)

In-service date: 12/22/2006

Brief Description of Project (sufficient to determine that the project is Capital not O&M)

ML2-S-PRECIPITATOR TR SET REPL

Company	LEG-9 #	Originated
Ohio Power Co.	No	08/18/2006

Originator	Project Manager	CI Approval Required by
Jason A Horn	Edward V Gilabert	09/15/2006

Originator Phone No.	Project Manager Phone No.	Amount to be Authorized
8-200-1589 614-716-1589	8-200-1765 614-716-1765	$9,367,979.00

Approved by PMRG Board:	Date Approved by PMRG Board:
Yes	06/15/2005

Will material become obsolete as a result of this CI? Yes

Have these costs been included in associated O&M? Yes

If you have questions concerning Obsolete Material, please contact your Supply Chain Representative.

Budget (Direct Costs)	Prior Years	YR1 2005	YR2 2006	YR3 2007	YR4 2008	YR5+ 2009+	Total
Capital - Direct	0	4,437,000	1,335,000	0	0	0	5,772,000
Removal - Direct	0	0	0	0	0	0	0
Total Direct Budget	0	4,437,000	1,335,000	0	0	0	5,772,000
Associated O&M	0	700,000	156,000	0	0	0	856,000
Capital - Direct	0	4,437,000	3,861,000	0	0	0	8,298,000
Removal - Direct	0	0	0	0	0	0	0

Project / CPP / Program Amount Being Authorized

	Prior Years	2005	2006	2007	2008	2009+	Total
Capital - Direct	0	4,437,000	3,861,000	0	0	0	8,298,000
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs to be Authorized	0	4,437,000	3,861,000	0	0	0	8,298,000
Capital - Overheads	0	221,850	193,050	0	0	0	414,900
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	221,850	193,050	0	0	0	414,900
AFUDC	0	136,504	518,575	0	0	0	655,079
Amount Being Authorized	0	4,795,354	4,572,625	0	0	0	9,367,979
Associated O&M	0	700,000	700,000	0	0	0	1,400,000

Total Capital	0	4,795,354	4,572,625	0	0	0	9,367,979
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	700,000	700,000	0	0	0	1,400,000

For revisions to previously approved projects - Previous Amount Authorized

	Prior Years	2005	2006	2007	2008	2009+	**Total**
Capital - Direct	0	4,115,533	2,428,682	0	0	0	6,544,215
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs Previously Authorized	0	4,115 533	2,428,682	0	0	0	6,544,215
Capital - Overheads	0	673,393	477,934	0	0	0	1,151,327
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	673,393	477,934	0	0	0	1,151,327
AFUDC	0	246,194	409,469	0	0	0	655,663
Amount Previously Authorized	0	5,035,120	3,316,085	0	0	0	8,351,205
Associated O&M	0	991,000	409,000	0	0	0	1,400,000

Total Capital	0	5,035,120	3,316,085	0	0	0	8,351,205
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	991,000	409,000	0	0	0	1,400,000

Incremental Amount to be Authorized (Calculated)

	Prior Years	2005	2006	2007	2008	2009+	**Total**
Capital - Direct	0	321,467	1,432,318	0	0	0	1,753,785
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs Difference	0	321,467	1,432,318	0	0	0	1,753,785
Capital - Overheads	0	(451,543)	(284,884)	0	0	0	(736,427)
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	(451,543)	(284,884)	0	0	0	(736,427)
AFUDC	0	(109,690)	109,106	0	0	0	(584)
Amount Difference	0	(239,766)	1,256,540	0	0	0	1,016,774
Associated O&M	0	(291,000)	291,000	0	0	0	0

Total Capital	0	(239,766)	1,256,540	0	0	0	1,016,774
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	(291,000)	291,000	0	0	0	0

Ownership Unit Breakdown

Funding # / Company	*	**Prior Years**	**2005**	**2006**	**2007**	**2008**	**2009+**	**Total**
ML2SCO004	C	0	4,795,354	4,572,625	0	0	0	9,367,979
	R	0	0	0	0	0	0	0
Ohio Power Co - Generation **Total**		0	4,795,354	4,572,625	0	0	0	9,367,979

* C = Total Capital, R = Total Removals

Mark A Gray	08/25/2006 10:38 AM EDT
Don Eng	08/28/2006 01:38 PM EDT
John M McManus	08/28/2006 01:48 PM EDT
Michael W Rencheck	08/28/2006 03:22 PM EDT
William L Sigmon	09/05/2006 03:37 PM EDT

Comments

Michael H Huggett - 08/24/2006 11:30:40 AM
An offset of $1,591K will be required prior to CI approval

Attachments

ML2SC0004 PMRG template Version 02.xls

Budget Availability for this Authorization:	2005	2006	Total
Original budget amount:	4,437,000	1,335,000	5,772,000
Offset (source & amount): TC407OCS1	-	2,527,000	2,527,000
Total	4,437,000	3,862,000	8,299,000

Regulatory Comments:

Selwyn J Dias - 08/29/2006 03:11:19 PM
OPCo's generation rates automatically increase through 12/31/08 No other mechanism for cost recovery in Ohio

AMERICAN ELECTRIC POWER

Mitchell 2 T/R Set Replacement

Unit	Mitchell 2	Funding Numbers	ML2SCO004		Date / Project Mgr.	Ed Gilabert
Category Code	Safety	Operating Company (s)	Ohio Power Co.	-	Unit Role	Base

Project Description	Replacement of PCB filled T/R sets with new non PCB conventional and high frequency T/R sets (SIR) Controls for conventional T/R sets will be upgraded as will rapper controls and communications Identical work was performed on Unit 1 in spring 2006. First portion of Unit 2 was completed in fall of 2005
Project Plan	Unit 2 has 2 boxes, with 112 PCB filled T/R sets They will be replaced with 96 new conventional non PCB filled T/R sets, 32 High frequency 70kV, 800mA T/R sets [requires addition of two 575V to 480V transformers to operate available SIR's] Cabinet controls for the installed T/R sets will be upgraded along with rapper controls and communications Key interlock system will also be replaced.
Schedule	First portion completed in fall of 2005. Outage for second portion starts September 2006 and ends December 2006
Project Justification	■ Improved particulate collection from more power in the box ■ Improved safety and environmental compliance with removing PCB filled T/R sets ■ Improved safety with new key interlocks and fire detection systems ■ Replace underrated power cable and other components including grounding grid ■ Replace deteriorating cable tray on roof and some vertical portions ■ Upgrade T/R set controls and rapper controls to provide better communication and overall performance in the boxes ■ 10,000 6-minute opacity exceedences since 1995 and $2 1 Million in lost generation due to opacity and other ESP related curtailments between 1997 and 2004 at Mitchell Plant (Both Units) ■ Increase current density in the boxes from 58 mA/1000ft2 closer to the fleet average of 80 mA/1000ft2
CI Revision Justification	■ Delayed R&D of higher power SIR forced a change to current generation lower power SIR ■ Use of lower power SIR resulted in scope change from 64 SIR's and 64 conventional to 32 SIR's and 96 conventional ■ Scope change above resulted in additional components to support the new electrical infrastructure ■ Higher than estimated 2005 labor and material due to scope change ■ Higher than estimated 2006 labor projections due to scope change
Alternatives Considered	One alternative considered includes installing 32 conventional T/R sets and leaving the remaining 32 high frequency T/R sets for a future outage This would leave either 16 PCB filled T/R sets on the ESP until the next outage that is 5 weeks or longer This would save approximately $0 5 million in installation labor during 2006 but would not achieve the goal of elimination all PCB T/R sets at Mitchell until the next outage Cost of stores, additional mobilization and labor escalation for the future year has not been obtained.
Financial Analysis Summary	This is an environmental and safety related project and as such, the typical cost/benefit analysis is not provided

	Year	2005	2006	2007	2008	2009	Total ($)
Cash Flow (Requested) Direct Costs	Original CI	$4,115,533	$2,428,682				$6,544,215
	Material	$2,652,000	$1,590,000				$4,242,000
	Labor	$1,118,000	$1,690,000				$2,808,000
	FODA	$290,000	$253,000				$543,000
	Contingencies	$377,000	$328,000				$705,000
	Total Direct	$4,437,000	$3,861,000	$0	$0	$0	$8,298,000
	Delta in CI vs Request	($321,467)	($1,432,318)	$0	$0	$0	($1,753,785)
Loaded Costs	Amount to be Authorized	$4,795,354	$4,572,625				$9,367,979
	Associated O&M	$700,000	$700,000				$1,400,000

Additional Notes:

Project and Field Services took over the project in Spring of 2006 and thus owns the CI. Engineering Services - AECE assisted P&FS with the financial and technical analysis of the project and preparation of the CI revision.

	Revised CI	Original CI	Delta
Material	$4,242,000	$4,058,690	$183,310
Labor	$2,808,000	$1,638,100	$1,169,900
FODA	$543,000	$398,775	$398,775
Contingencies	$705,000	$448,650	$256,350
Direct Total	**$8,298,000**	**$6,544,215**	**$1,753,785**
AFUDC	$655,079	$655,663	($584)
OH	$414,900	$1,151,327	($736,427)
Indirect Total	**$1,069,979**	**$1,806,990**	**($737,011)**
CI Total	***$9,367,979***	***$8,351,205***	***$1,016,774***
Removal (O&M)	$1,400,000	$1,400,000	$0

Approved by the PMRG Board _____

Unit: WSNRG **Project ID:** ML2SCO004 **Description:** ML2-S-PRECIPITATOR TR SET REPL

Delete **Last OPRID:** S187426 Jason A Horn **Last Update Dttm:** 08/18/06 10:38:41AM View Change Log

Capital Improvement Estimate

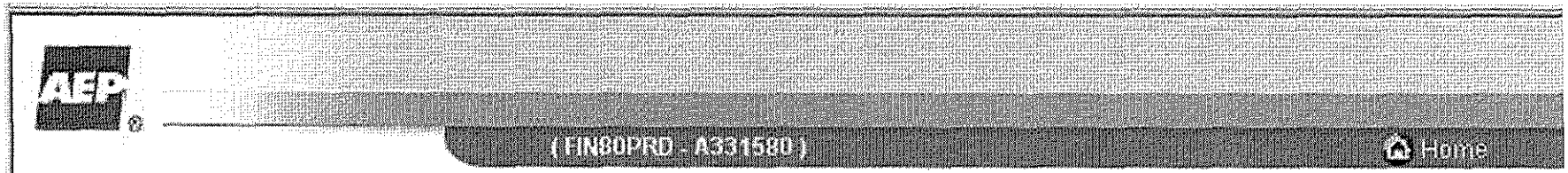
Version: 2 **Est. Status:** Initiated **CPP/Program:**
***Funding Proj Type:** 111285 OPCo Gen CI - Fossil/Hydro
***Start Date:** 03/01/2005 ***In Service:** 12/22/2006
***Sub Juris ID:** OHIO PWR_G Ohio Power Generation
***Environ Code:** Air Pollution
Mandatory Reason: Safety
***Major Location:** 63 Mitchell Generating Plant
BU Approver:
Project Manager: 4212194 Gilabert,Edward V
Approval Date:

Scores Risks Rates Recalc Approve Reject

Cost Categories	TOTAL	2005	2006	2007	2008	2009
Capital						
Internal Labor	543,000.00	290,000.00	253,000.00			
Outside Services	2,808,000.00	1,118,000.00	1,690,000.00			
Material	4,242,000.00	2,652,000.00	1,590,000.00			
Other	705,000.00	377,000.00	328,000.00			
Fleet						
Fringes						
Expense						
Internal Labor						
Outside Services						
Material						
Other	1,400,000.00	700,000.00	700,000.00			

Costs Calcs - If checked, override amount is displayed.					
Total Direct Capital		8,298,000.00	4,437,000.00	3,861,000.00	
Total Direct Removal					
Total Direct		8,298,000.00	4,437,000.00	3,861,000.00	
Total Dir Cap+Fleet+Fringe		8,298,000.00	4,437,000.00	3,861,000.00	
Cap Overheads - Standard	☐	414,900.00	221,850.00	193,050.00	
AFUDC Basis			4,658,850.00	8,849,404.00	
AFUDC Debt - Standard	☐				
AFUDC Equity - Override	☑	655,079.00	136,504.00	518,575.00	
Total Capital		9,367,979.00	4,795,354.00	4,572,625.00	
Total Removal					
Total Approved Project Cost		9,367,979.00	4,795,354.00	4,572,625.00	
Total Expense		1,400,000.00	700,000.00	700,000.00	
CIAC/Other Credits					
Total Project Cost		10,767,979.00	5,495,354.00	5,272,625.00	
Accum Total Project Cost			5,495,354.00	10,767,979.00	10,767,979.00
Accum Tot Cap Less CIAC			4,795,354.00	9,367,979.00	9,367,979.00

Other Categories	TOTAL	2006	2007	2008	2009	2010	2011	2012	2013
Market Revenue									
3rd Party Revenue									
Total Revenue									
Savings/Avoided Costs									
Credits									
Total Project Benefits									
Incremental Costs									
EBITDA (Margin)									
Tax Depreciation	4,979,455.54	351,299.21	676,274.40	625,499.96	578,660.06	535,192.64	495,097.69	457,906.81	423,620.01
EBIT	-4,979,455.54	-351,299.21	-676,274.40	-625,499.96	-578,660.06	-535,192.64	-495,097.69	-457,906.81	-423,620.01
Accum Tax Depreciation		351,299.21	1,027,573.61	1,653,073.57	2,231,733.63	2,766,926.27	3,262,023.96	3,719,930.77	4,143,550.78
Net Tax Value		9,016,679.79	8,340,405.39	7,714,905.43	7,136,245.37	6,601,052.73	6,105,955.04	5,648,048.23	5,224,428.22
Book Depreciation	3,345,706.80	334,570.68	334,570.68	334,570.68	334,570.68	334,570.68	334,570.68	334,570.68	334,570.68
Accum Book Depreciation		334,570.68	669,141.36	1,003,712.04	1,338,282.72	1,672,853.40	2,007,424.08	2,341,994.76	2,676,565.44
Net Book Value		9,033,408.32	8,698,837.64	8,364,266.96	8,029,696.28	7,695,125.60	7,360,554.92	7,025,984.24	6,691,413.56
Terminal Value	5,417,785.17								
Property Tax	1,514,300.36	96,657.47	186,155.13	178,995.31	171,835.50	164,675.69	157,515.88	150,356.06	143,196.25
Taxable Income	-6,493,755.90	-447,956.68	-862,429.53	-804,495.27	-750,495.56	-699,868.33	-652,613.57	-608,262.87	-566,816.26
Tax (composite)	-2,402,689.68	-165,743.97	-319,098.93	-297,663.25	-277,683.36	-258,951.28	-241,467.02	-225,057.26	-209,722.02
After Tax Cash Flow	888,389.32	69,086.50	132,943.80	118,667.94	105,847.86	94,275.59	83,951.14	74,701.20	66,525.77
Retirement									
Salvage									
Total Project Cash Flows	-4,461,804.51	-10,698,892.50	132,943.80	118,667.94	105,847.86	94,275.59	83,951.14	74,701.20	66,525.77
Accum Total Project Cash Flows		-10,698,892.50	-10,565,948.70	-10,447,280.76	-10,341,432.90	-10,247,157.31	-10,163,206.17	-10,088,504.97	-10,021,979.20



Home > Process Financial Information > Coordinate Budgets > Use > **Project General**

Project General | Project Tree | CI

Business Unit: WSNRG Wholesale Non Regulated

***Project ID:** ML2SCO004

***Description:** ML2-S-PRECIPITATOR TR SET REPL

Project Summary

Integration: ALL_PROJECTS Default - All Projects

Project Type: MPECS Projects Environmental Capital

***Project Category:** PRECIP Precipitator

Project Class: GEN Generation

Project Status: 2 Open

All Allowed Budgets

ABD	RD
NR	SCNA
PC	SCNM
PCGEN	SCWO
OPWO	EXPWO

Description View All 1 of 1

Date/Time Stamp: 07/06/04 12:30:47PM

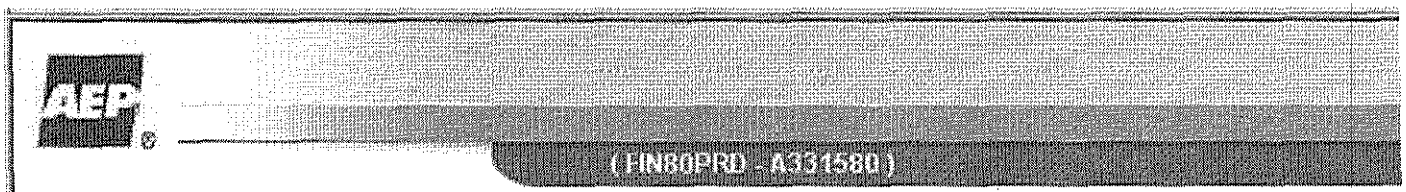
User ID: I548419

***Description:**

ML2-S-PRECIPITATOR TR SET REPL

Long Description:

ML2-S-PRECIPITATOR TR SET REPL



Home > Process Financial Information > Coordinate Budgets > Use > **Project General**

Project General | Project Tree | CI

Unit: WSNRG **Project ID:** ML2SCO004 **Description:** ML2-S-PRECIPITATOR TR SET REPL

*Tree Name: WHOLESALE_NON_REG

*Effective Date of Tree: 01/01/1901

*Parent Tree Node: 00000285

*GL Business Unit: 181 Ohio Power Co - Generation

CI Value: ML2SCO004 ML2-S-PRECIPITATOR TR SET REPL

*Project Initiator: 548419 Darryl P Lynch

In Service Date: 12/31/2006

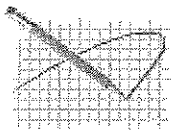
Sub Jurisdiction ID: OHIO PWR_G Ohio Power Generation

Summary/Switch

- Allow Workorders(This is a Detail Project)
- Do not Allow Workorders(This is a Parent Project)

Save | Return to Search | Refresh

Tuesday, Sep 05, 2006 03:45 PM



CI - LI Routing
Sent by: William L Sigmon

09/05/2006 03:37 PM

Please respond to
CI - LI Routing

To Kevin E Walker/AEPIN@AEPIN, John F Torpey/OR4/AEPIN@AEPIN, Patricia D Bachman/OR4/AEPIN@AEPIN, Paula L
cc
bcc
Subject CI/LI #ML2SCO004 has been Approved.

CI/LI #ML2SCO004 (ML2-S-PRECIPITATOR TR SET REPL) is approved and available for review at your convenience.

To review or act upon the request, please follow this link. ->>

Date May 9, 2008

Company	CI/LI/CPP/Program Number	Version
Ohio Power	ML001FGD0	5

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	RB 05/09/08		RB 05/09/08

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	J. R. Frederick		
1	J. Martin	JFM 5/12/08	
2	R. E. Munczinski	JFM for REM 5/12/08	
	H. Koeppel		
	M. Heyeck		
	S. Tomasky		
	M. W. Rencheck		
	Scott N. Smith		
	N. K. Akins		
	Steve P. Smith		
	D. E. Welch		
	B. X. Tierney (East > $10 million)		
	T. M. Hagan (West > $10 million)		
	R. P. Powers		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
3	M. G. Morris	MGM 5.14.08	
4	Pat Bachman - 28th floor Ext 2888		
		05/14/08	Approved in PeopleSoft
			Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Christine Gaston - 28th Floor - Ext 5994

Scanned File Name: Ohio Power ML001FGD0 Version 5.pdf

CPP APPROVAL REQUISITION

Company: Ohio Power Company **CPP Number:** ML001FGD0

Authorization Type: Capital Planning Proposal Version Number: 5

Business Line: Generation

Location: Mitchell Generating Plant

Project Title: ML U1 WFGD/SCR Phase III Engineering, Procurement, and Construction

Business Reason: Environmental, Safety and Health

Brief Description: Revised authorization to complete ESP stiffening as part of the balance draft conversion design and install flue gas pressure drop modifications.

Regulatory Cost Recovery:

- $503.8M (94%) Rates automatically increased 7% on 1/1/2008. No other mechanism for generation or environmental cost recovery currently exists in Ohio. New regulations will not take effect until 1/1/09; only carrying charges on CWIP for environmental-related equipment will be recovered, but this project will be closed to plant in-service before 1/1/09.
- $32.2M (6%) FERC Annual Formula Rate Update. TYE 12/31/08, effective 7/1/09.

Project Dates:	Start:	Completion:	In-Service:
	10/01/2001	11/01/2008	05/07/2007

Expenditure to be Authorized (fully loaded)

	Capital ($)	Removal ($)	Total ($)
Previously Approved Amount	506,538,334	0	506,538,334
This Submission	29,443,744	0	29,443,744
Total ($)	**535,982,078**	**0**	**535,982,078**

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior Vice President	McCullough, M.	See attached	
$ 10m ≤ amt < $ 20m	Executive Vice President	Akins, N.	See attached	
amt ≥ $ 20m	Chairman, President & CEO	Morris, M.		5.14.08
CP&B Review	Senior Vice President	Munczinski, R.		

2008 Direct Cost Budget Availability for this Authorization: $ 5.9M In Budget $21.6M Offset

If offset, indicate source and amount: **ACI Program $9.8M, Budget Shift $11.6M, FODA, $300K**

Requested future year amounts are included in or offset within the Strategic Plan Capital Forecast.

CPP APPROVAL REQUISITION

Cash Flow (fully loaded)

Year	Prior Years	2008	2009	2010	Future Years	Total ($)
Capital	505,940,675	30,041,403	0	0	0	**$535,982,078**
Removal	0	0	0	0	0	**0**
Total to be Authorized	505,940,675	30,041,403	0	0	0	**$535,982,078**
Assoc. O & M	6,715,962	0	0	0	0	**6,715,962**

Note: Associated O & M is not approved with this requisition. Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

Financial Analysis Summary

The decision to install this technology was made in the context of an AEP system wide environmental compliance analysis which identified that this project was a critical element in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the multi-emissions compliance optimization model (MECO), a unique mixed integer programming model which solves for the least cost environmental compliance plan. The model considers power and emission allowance markets, load demand forecast, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. This proprietary model is a sophisticated analytic tool that allows the company to systematically weigh costs and risks of a wide variety of options and allows simultaneous optimization across multi-emissions (SO2, NOx, mercury and CO2).

Component CIs

CI Number	Description of Work	Previously Approved Amount ($)		This Submission ($)		Subtotal ($)		Total ($)
		Capital	Rem	Capital	Rem	Capital	Rem	
WSX115086	FGD/SCR scope of work	398,053,316	0	3,417,948	0	401,471,264	0	401,471,264
ML001BALD	Balanced Draft Conversion	33,704,796	0	28,356,719	0	62,061,515	0	62,061,515
ML001DCS0	Controls Modernization	3,623,475	0	400,959	0	4,024,434	0	4,024,434
ML001BMOD	Steam Generator Modifications	15,283,549	0	(944)	0	15,282,605	0	15,282,605
ML001SO3M	SO_3 Mitigation System	11,995,421	0	(1,065,553)	0	10,929,868	0	10,929,868
ML001PURG	Purge Stream Water Treatment System	26,678,127	0	(711,147)	0	25,966,980	0	25,966,980
ML001COAL	Coal Blending Station	17,199,649	0	(954,237)	0	16,245,412	0	16,245,412
Total ($)		**506,538,334**	**0**	**29,443,744**	**0**	**535,982,078**	**0**	**535,982,078**

Project Justification

Explanation of CI Revision Version 5

After startup of the Mitchell units in 2007, inadvertent design deficiencies associated with the balance draft conversion were evident when ESP ductwork deformation occurred which required additional ductwork stiffening to ensure structural integrity. This work was performed in the spring, 2007. A subsequent detailed re-assessment of the design determined that actual operating conditions exceeded the design basis and operating restraints were imposed on both units. To alleviate these operating

CPP APPROVAL REQUISITION

restraints, it is now necessary to install additional internal and external ESP reinforcement consisting of approximately 300 tons of structural steel. Upon completion of this added stiffening, the ESPs will be capable of operating at the design basis balanced draft pressures. External work will be completed with the unit in service and the internal work will be completed during the fall, 2008 outage. The estimated cost for the Unit 1 ESP stiffening is approximately $16.5 million in direct costs.

Funding is also requested to address excessive flue gas pressure drop issues. The pressure drop through the Trona ductwork, ESP, and old stack up to the ID fans is significantly higher than designed. This excessive pressure drop is curtailing the unit output by approximately 70 MW. Internal flow straightening ductwork modifications in the Trona ductwork, high performance air heater seals and a bypass around the old stack is planned to be installed during a fall 2008 outage to reduce the pressure drop and re-gain approximately 60 MW. The estimated cost for this scope of work is approximately $10.0 million in direct costs. Other areas are under evaluation for future modifications to further reduce pressure drop restrictions.

Explanation of CI Revision Version 4

AEP's "first mover" strategic position and early award of OEM and major installation labor contracts has facilitated our ability to mitigate, to a large extent, the inflationary impacts in the range of 10-15% that are being experienced by our peers in the electric utility industry. In addition, the project has largely mitigated the productivity impact associated with significant labor shortages experienced in the Ohio River valley labor pool during the peak construction period in 2006.

Both units have completed their respective tie-in outages and successfully returned to service. While the FGD and SCR costs have been mostly contained, the project continues to experience cost pressure as ancillary systems are completed and placed in service. We are currently forecasting to exceed authorized direct cost funding by approximately 4.2% or $37.2M.

During the final weeks of completion of the necessary activities to start up each unit, considerable overtime was expended as work proceeded towards completion according to schedule. In addition, there have been several events that have surfaced during the startup process, necessitating remedial and corrective actions and expenses.

Electrical: FGD electrical work has exceeded the target amount due to overtime and emerging work that was found during the execution of the contract work. Additional work was required for the SCR's, grounding, coal blending fiber optics and demobilization support. ($6.8M)

Material Handling (MH): Additional work and an increase in the man-hours were required for this contract, primarily related to the late foundation completion due to the RB bankruptcy. The proposed settlement with the MH contractor is reflected in this CI revision. There is also a need for additional funding to complete the fire protection work due to unforeseen delays by the main MH contractor. ($7.0M)

Waste Water Treatment: Remediation of the primary clarifier foundations and lower tank sections resulted in unplanned expenses. In addition, previously assumed back charge costs associated with outside engineering services have been limited by contractual terms, necessitating additional funding. ($3.7M)

Balanced Draft/Boiler Modifications: The current forecast, and this request, includes increased costs for unanticipated extra work associated with the Trona modifications for controlling SO3 emissions and extra work associated with the balanced draft modifications to the boiler. The costs associated with the remediation of the precipitator outlet plenums associated with the balanced draft stiffening are also included in this request. ($16.6M)

CPP APPROVAL REQUISITION

Miscellaneous Site Support: AEP Services have increased in proportion to the support required to interface with the ongoing work, including temporary heat, grouting and general site support transportation and sanitary services. ($3.1M)

Explanation of CI Revision Version 3

On March 4, 2006, the Mitchell project experienced a fire in the stack being constructed as a part of the Mitchell FGD / SCR / Associated projects CI. The fire severely damaged the construction of the stack liner that had taken place on the stack. In addition, the fire also had significant impacts on the progress of all work taking place at Mitchell as the entire site was affected by schedule delays, site restrictions, and re-sequencing of work activities.

As a result of this fire certain costs associated with the recovery from the stack fire were presented to AEP's Risk & Insurance Management department for recovery under AEP's applicable insurance policies. From March 2006 through November 2006, the Mitchell Project Management team, along with support

from Project & Field Services and Generation Business Services, worked to identify "known" impacts from the stack fire event and provide information to Risk & Insurance Management for review.

On December 5, 2006, Project & Field Services and Generation Business Services were notified by AEP's Risk & Insurance Management department that after review of the information provided for recovery under AEP's insurance policies, there were a considerable number of items that were not subject to recovery under any of AEP's applicable insurance policies.

The following excerpts were taken from the notification received from AEP's Risk & Insurance Management department:

> "After review and discussion of the cost items pertaining recovery from the Mitchell stack fire with GBS, P&FS, and our adjusters at Crawford, Risk & Insurance Management has identified certain expense items that are not insured under the AEP corporate property insurance policy, as written at the time of the loss."
>
> "AEP's insurance covers direct physical loss or damage to property in the course of construction for the interest of contractors, where provided by contract, and for the interest of AEP. Additionally, our insurance provides coverage for expediting expenses as it relates to damaged property; to demolition or increased cost of construction incurred when the enforcement of any law or ordinance regulates the repair or reconstruction of damaged and undamaged property; debris removal expense due to physical loss or damage; decontamination and clean up expense where the physical loss or damage is paid or agreed to be paid by the Insurer; fire brigade charges and extinguishing expense resulting from physical loss or damage insured by the policy."
>
> "Extra Expense and Delay in Start-Up costs and the associated expense to reduce these types of costs are not insured."
>
> "A substantial element of the costs was consequential delay expense incurred by AEP for undamaged or un-constructed project work under several contracts: B&W; MJ Electric; Chapman; Enerfab. In order for AEP to remain on schedule, decisions were made to increase the weekly length of labor hours incurred per week."
>
> "Another aspect of the information include AEP internally incurred and anticipated costs. Although these are not completely supported, adequate discussion to gain an understanding surrounding the nature of these items indicates they are not insured expenses."
>
> "Lastly, this submittal has an estimate under the Pullman section for additional amount of $8,700,000. Of this amount, $6,000,000 represents additional cost to undamaged and un-constructed project work yet to be completed. This additional cost is due to congestion in the work area and completing the work on the second liner after the first liner is operational."

CPP APPROVAL REQUISITION

After evaluating the "known" costs that have been identified by AEP's Risk and Insurance Management as "Not Subject to Insurance Recovery" ($16.5M), as well as pending or future costs that may be incurred by AEP associated with the stack fire, this CI Revision is being routed for $25.0M (Units 1 & 2 Combined) to cover all costs associated with this event. Although not covered by insurance, AEP has incurred (and continues to incur) a significant cost impact to the project as a result of the stack fire. These costs were clearly not foreseen when the original CI was prepared.

Explanation of CI Revision Version 2

- Please reference the attached presentation for an overview of the CI revision, project update, and the cost containment strategies that are in place on the project.

- Two significant and unforeseen events have occurred since the Phase III CI Authorization was approved.

  √ The primary civil / foundation contractor, Ragnar Benson, Inc., declared bankruptcy while working on the project and ceased all work activity.
    - This event impacted foundation completion, delayed critical path, compressed the overall schedule, increased site peak manpower requirements, and created significant site logistics issues.
    - In order to attempt to maintain schedule and, to the extent possible, mitigate impacts on other contractors, AEP was required to complete the remaining scope of work abandoned under Ragnar Benson's firm price contract by utilizing on-site contractors at an increased cost to the project.

  √ The Mitchell stack fire incident had a significant impact on the execution of the project. The project experienced a loss of progress, sixty (60) day schedule impact, re-sequencing of work activities, and significant schedule compression.

- FGD / SCR

  √ AEP's "first mover" strategic position and early award of OEM and major installation labor contracts has facilitated our ability to mitigate, to a large extent, the inflationary impacts that are being experienced by our peers in the electric utility industry.

  √ On a direct cost basis, the SCR and FGD costs (Units 1 & 2) have been contained at approximately 4% and 5%, respectively. Most of this increase is directly associated with the two unforeseen events mentioned above.

- Associated Projects

  √ The associated projects were originally budgeted based upon engineering concepts. Design details were developed during outage inspections and with integration of SCR / FGD components. These design details were completed in 2005, subsequent to the Phase III CI Authorization.

  √ The completion of engineering and labor contracting on the associated projects occurred in 2006, after the construction market began to reflect considerable market escalation.

  √ In the Phase III CI Authorization, a preliminary $20 million "placeholder" was budgeted for Purge Stream Waste Water Treatment, based on limited industry benchmarking. Subsequent site and process specific engineering and design work, coupled with the securing of valid proposals for installation labor and equipment have been completed. With specific management focus, oversight and control, the forecasted cost of this project is still expected to be $40M, double the preliminary estimate used in the Phase III CI Authorization.

CPP APPROVAL REQUISITION

√ The results of the impacts noted above, mitigated by direct management intervention and strict control culminates in the associated project's direct cost forecasts being limited to approximately 38% from the Phase III CI authorization.

Project Justification

- The decision to install WFGD and SCR systems at Mitchell was made in the context of an AEP system wide environmental compliance analysis which identified that scrubbing Mitchell Unit 1 and installing a SCR system were critical elements in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the MECO (multi-emissions compliance optimization) model, a unique mixed integer programming model, which solves for the least cost environmental compliance plan. The model considers power and emission allowance markets, load demand forecast, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. This proprietary model is a sophisticated analytic tool that allows the company systematically to weigh the costs and risks of a wide variety of options and allows simultaneous optimization across multi-emissions (SO_2, NOx, mercury and CO2).

  In July 2003, the company analyzed a variety of potential environmental scenarios, including the current SO_2 and NOx regulations faced by the company under Title IV and the NOx SIP Call under the Clean Air Act of 1990 plus a variety of additional reductions under EPA's future regulatory initiatives for fine particulates, visibility, and ozone attainment initiatives. In addition, potential multi-emissions regulations such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Mitchell Plant WFGD/SCR decision was always a critical element of the least cost compliance plan.

  In January 2004, AEP reanalyzed the compliance plan in light of the proposed EPA clean air interstate rule (CAIR) and the mercury rules (proposed in December 2003) and reached an identical conclusion. The Mitchell Unit 1 WFGD and SCR were again found to be an economic decision.

- In January 2005, updated capital costs and fuel pricing were entered into the WFGD model and Mitchell Plant was again selected for scrubbing as were retrofits necessary to burn low-cost high sulfur coal as part of AEP's least cost compliance plan. In addition, under all the scenarios analyzed, the fuel and operating costs of Mitchell Unit 1 plus the WFGD investment (incremental capital) and additional O&M costs were well below market prices for power now and projected in the future, indicating that the investment in Mitchell was sound and robust relative to market alternatives.

- In order to meet the Mitchell Unit 1 WFGD/SCR 2007 in-service date, Phase III CI funding is required to continue and complete detailed engineering, design, scheduling, environmental planning, permitting, procurement, and construction to obtain operational WFGD and SCR systems at Mitchell. Phase III includes the erection of the WFGD, SCR and Balance of Plant (BOP) equipment and system startup.

- Specifically, Phase III will build upon the engineering and budgetary cost estimates from Phase II and continue with detailed engineering, design and construction. Construction labor Request for Quotation (RFQ) Packages were issued for competitive pricing and have become the basis of the Phase III requested labor funding for the WFGD project. A firm price for the SCR construction has been established, also through the use of competitive pricing.

- Phase III funds the selected A/E through completion of detailed engineering, design, and construction in 2007. Phase III also funds the selected WFGD and SCR OEMs to continue design and equipment selection, to support the construction and in-service schedule. Funding for Phase III also supports internal AEPSC engineering, design, air permitting efforts, project management and construction services through completion of the project.

CPP APPROVAL REQUISITION

Other Alternatives Considered

- The SO_2 Compliance Plan has evaluated several alternatives such as the procurement of SO_2 allowances on the open market and/or fuel switching, but these alternatives will not provide the amount of SO_2 allowance required to support AEP's coal-fired electrical generation fleet.

- Alternatives to the SCR technology that were considered include buying needed NOx emissions allowances in the marketplace, Over-Fired Air (OFA), Water Injection, OFA & Water Injection, SNCR, OFA & PRB Fuel Blend, AEFLGR, Gas Reburn, and PRB Fuel Blend. Reliance on an uncertain marketplace for NOx emissions allowances is an unacceptable compliance strategy and would place the Company and its ratepayers at an unacceptable risk of noncompliance. The alternatives to the application of SCR technology are, in some cases, not as cost effective as SCR and, in all cases, unable to achieve the reduction required at Mitchell to meet the applicable NOx requirements for the AEP System.

Conclusion

- This request for funding to complete engineering, design, procurement, construction, and start-up is required to support the WFGD and SCR schedule.

- This strategy supports the construction of WFGD and SCR systems at Mitchell Unit 1 for operation April 2007.

Associated / Future Projects

The AEP Fleet Compliance Plan, to address emissions regulations in the most cost-effective manner, relies on the efficient and reliable operation of the controlled Units. The associated projects identified below are intended to provide greater operational flexibility in this area and addressing overall reliability. The complexity of the associated projects and their interaction between the WFGD and the SCR requires continuing review to optimize scope, costs and schedule. These projects are consistently selected as a key part of the low cost compliance plan through MECO model analysis.

Steam generator additions to allow the use of the most economic high sulfur coal have been analyzed as a part of the WFGD project. The following associated projects are included in Phase III.

- **Balance Draft Conversion** – The installation of WFGD necessitates the implementation of new fans to overcome the additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balanced draft condition). Converting to balance draft design concurrent with a WFGD retrofit enables the Unit to combust high sulfur lower cost coal, consistently provides a less hazardous work environment, mitigates reduction in unit availability and reduces potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - A portion of the SO_2 generated during coal combustion is oxidized to SO_3 in the steam generator and further oxidized in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from both the steam generator and SCR. Without additional controls, the stack SO_3 levels are projected to exceed the stack targeted control range and could contribute to a blue plume opacity in the flue gas exiting the stack. The installation of a magnesium hydroxide slurry injection system into the upper furnace of the steam generator will reduce SO_3 exiting the boiler. The SCR will be designed to utilize low SO_2 to SO_3 conversion rate catalyst to minimize the amount of SO_3 converted in the SCR. The remaining SO_3 levels will be reduced to the control range via use of the existing ammonia injection system.

- **Unit Controls Modernization** – The installation of WFGD and SCR technologies will utilize a state of the art control system. This new, modern DCS system will be integrated into the existing

unit controls, which will be incrementally modernized so as to make this work feasible. "Stand-alone" controls for the WFGD and SCR are not desirable.

- **Fuel Blending Capabilities –** On-site blending capability adds significant flexibility for the procurement of the most economic fuel. The economies of burning high sulfur coal have been analyzed as part of the WFGD project and are supported by the economic models. Mitchell plant has the tunnel and chute capacity and a radial stacker that will accommodate a blending operation. There are conveyors that would need to be added and/or upgraded to allow blending.

- **Steam Generator Additions –** Building on the fuel flexibility benefits, for Mitchell Plant to combust coals with sulfur contents as high as 4.5#/MBtu, the steam generator will require some changes, including installation of a new rear wall arch, additional furnace slag control devices (water cannons and/or blowers), furnace overlay to mitigate increased furnace corrosion, and boiler instrumentation upgrades.

- **River water Makeup Pump Upgrades -** The water demands of the WFGD and SCR systems exceed the existing capacity of the river water makeup system. Review of various options to increase system capacity has determined that the most economic approach is to replace the existing pumps and motors with higher flow capacity pumps/motors. This will assure reliable water supply for plant needs as well as the WFGD and SCR.

- **Purge Stream Water Treatment –** Initial evaluation of the potential purge stream water contents indicates that treatment may be required. Further studies are in progress to determine the extent of treatment if any, which may be required. In order to maintain the current schedule, a preliminary estimate of $20 million is allocated to fund this portion of the work. This number was determined from benchmarking the industry and input from the AE and will be accurately determined late in the second quarter of 2005.

Additional Information

Regulatory Issues

- Existing regulations under Title IV of the Clean Air Act, as well as regulations currently under development by the U.S. EPA, along with other alternatives to the Clean Air Act being considered by Congress such as Clear Skies and the Carper Bill, will require AEP to reduce emissions of SO_2 in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. U.S. EPA proposed in December 2003 regulation of interstate air quality that, if promulgated, will require significant additional SO_2 and NO_x emission reductions beginning in 2010. U.S. EPA also proposed in December 2003 regulation of mercury emissions from coal-fired power plants. Mercury emission reductions can be achieved with a combined SCR and WFGD system. In addition to these proposed regulations, the existing Title IV acid rain control program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

Background Information

- The WFGD technology is targeted to be capable of 98% SO_2 removal efficiency. This level of removal will allow for an expected 95% reduction in annual emissions during all modes of operation. The reagent will be limestone, and the technology will provide the operational flexibility to produce a wall-board quality gypsum by-product. The WFGD design criteria provide maximum fuel flexibility by allowing for the burning of high sulfur coal.

- The WFGD design basis for this unit includes provisions for adding future emission control equipment for reduction of mercury and possibly other emissions without relocation of equipment. This approach will allow for implementation of current emerging technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

- The SCR system will be designed for a 90% NOx removal rate with an allowable maximum ammonia slip of 2 ppmv (at 3% O_2) and a design catalyst life that minimizes the life cycle costs. A urea to ammonia conversion system will be used to supply the SCR reactors with reagent.

Project Contacts

Contact	Name	Telephone
Project Manager	Ed Gilabert	(614) 716-1765
Requisition Detail Provider	William King	(614) 716-1791

Date March 27, 2008

Company	CI/LI/CPP/Program Number	Version
Ohio Power	ML002FGD0	5

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	RB 03/27/08		RB 03/27/08

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	J. R. Frederick		
1	J. Martin	JFM 3/27/08	
2	R. E. Munczinski	REM 3/28/08	
	H. Koeppel		
	M. Heyeck		
	S. Tomasky		
	M. W. Rencheck		
	Scott N. Smith		
	N. K. Akins		
	Steve P. Smith		
	D. E. Welch		
	B. X. Tierney (East > $10 million)		
	T. M. Hagan (West > $10 million)		
	R. P. Powers		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
3	M. G. Morris		
4	Pat Bachman - 28th floor Ext 2888		
		04-04-08	Approved in PeopleSoft
			Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Christine Gaston - 28th Floor - Ext 5994

Scanned File Name: Ohio Power ML002FGD0 Version 5.pdf

CPP APPROVAL REQUISITION

Company: Ohio Power Company **CPP Number:** ML002FGD0

Authorization Type: Capital Planning Proposal Version Number: 5

Business Line: Generation

Location: Mitchell Generating Plant

Project Title: ML U2 WFGD/SCR Phase III Engineering, Procurement, and Construction

Business Reason: Environmental Safety and Health

Brief Description: Revised authorization to complete the ESP stiffening as part of the balance draft conversion design for Mitchell Unit 2.

Regulatory Cost Recovery:

- $486.68M (94%) TBD (rates automatically increase 7% on 1/1/2008). No other mechanism for cost recovery currently exists in Ohio, pending establishment of post-RSP rules.
- $31.07M (6%) FERC filing or Annual Generation Formula Rate Update

Project Dates:	Start:	Completion:	In-Service:
	10/01/2001	05/01/2009	04/30/07-5/1/2009

Expenditure to be Authorized (fully loaded)

	Capital ($)	Removal ($)	Total ($)
Previously Approved Amount	496,000,086	0	496,000,086
This Submission	21,754,407	0	21,754,407
Total ($)	**517,754,493**	**0**	**517,754,493**

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior Vice President	McCullough, M	see attached	
$ 10m ≤ amt < $ 20m	Executive Vice President	Akins, N.	see attached	
amt ≥ $ 20m	Chairman, President & CEO	Morris, M.		4.4.08
CP&B Review	Senior Vice President	Munczinski, R.		

2008 Direct Cost Budget Availability for this Authorization: $ 5.9M In Budget $ 335K Offset

If offset, indicate source and amount: **FODA: $335K**

Requested future year amounts are included in or offset within the Strategic Plan Capital Forecast.

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Cash Flow (fully loaded)

Year	Prior Years	2008	2009	2010	Future Years	Total ($)
Capital	500,171,757	6,492,536	11,090,800	0	0	**517,754,493**
Removal	0	0	0	0	0	**0**
Total to be Authorized	500,171,757	6,492,536	11,090,800	0	0	**517,754,493**
Assoc. O & M	6,423,238	0	0	0	0	**6,423,238**

Note: Associated O & M is not approved with this requisition. Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

Financial Analysis Summary

The decision to install this technology was made in the context of an AEP system wide environmental compliance analysis which identified that this project was a critical element in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the multi-emissions compliance optimization model (MECO), a unique mixed integer programming model which solves for the least cost environmental compliance plan. The model considers power and emission allowance markets, load demand forecast, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. This proprietary model is a sophisticated analytic tool that allows the company to systematically weigh costs and risks of a wide variety of options and allows simultaneous optimization across multi-emissions (SO2, NOx, mercury and CO2).

Component CIs

CI Number	Description of Work	Previously Approved Amount ($)		This Submission ($)		Subtotal ($)		Total ($)
		Capital	Rem	Capital	Rem	Capital	Rem	
WSX115137	FGD/SCR scope of work	402,113,583	0	32,745	0	402,146,328	0	402,146,328
ML002BALD	Balanced Draft Conversion	29,017,632	0	19,447,398	0	48,465,030	0	48,465,030
ML002DCS0	Controls Modernization	4,355,864	0	588,861	0	4,944,725	0	4,944,725
ML002BMOD	Steam Generator Modifications	10,684,505	0	(87,876)	0	10,596,629	0	10,596,629
ML002SO3M	SO_3 Mitigation System	10,985,233	0	(191,336)	0	10,793,897	0	10,793,897
ML002PURG	Purge Stream Water Treatment System	24,884,935	0	(146,253)	0	24,738,682	0	24,738,682
ML002COAL	Coal Blending Station	13,958,332	0	2,110,870	0	16,069,202	0	16,069,202
Total ($)		**496,000,086**	**0**	**21,754,407**	**0**	**517,754,493**	**0**	**517,754,493**

Project Justification

Explanation of CI Revision Version 5

After startup of the Mitchell units in 2007, inadvertent design deficiencies associated with the balance draft conversion were evident when ESP ductwork deformation occurred which required additional ductwork stiffening to ensure structural integrity. This work was performed in the spring, 2007. A subsequent detailed re-assessment of the design determined that actual operating conditions exceeded the design basis and operating restraints were imposed on both units. To alleviate these operating restraints, it is now necessary to install additional internal and external ESP reinforcement consisting of approximately 300 tons of structural steel. Upon completion of this added stiffening, the ESPs will be capable of operating at the design basis balanced draft pressures. External work will be completed with the unit in service and the internal work will be completed during the spring, 2008 outage. The estimated cost for the Unit 2 ESP stiffening is approximately $17.0 million.

Explanation of CI Revision Version 4

AEP's "first mover" strategic position and early award of OEM and major installation labor contracts has facilitated our ability to mitigate, to a large extent, the inflationary impacts in the range of 10-15% that are being experienced by our peers in the electric utility industry. In addition, the project has largely mitigated the productivity impact associated with significant labor shortages experienced in the Ohio River valley labor pool during the peak construction period in 2006.

Both units have completed their respective tie-in outages and successfully returned to service. While the FGD and SCR costs have been mostly contained, the project continues to experience cost pressure as ancillary systems are completed and placed in service. We are currently forecasting to exceed authorized direct cost funding by approximately 4.2% or $37.2M.

During the final weeks of completion of the necessary activities to start up each unit, considerable overtime was expended as work proceeded towards completion according to schedule. In addition, there have been several events that have surfaced during the startup process, necessitating remedial and corrective actions and expenses.

Electrical: FGD electrical work has exceeded the target amount due to overtime and emerging work that was found during the execution of the contract work. Additional work was required for the SCR's, grounding, coal blending fiber optics and demobilization support. ($6.8M)

Material Handling (MH): Additional work and an increase in the man-hours were required for this contract, primarily related to the late foundation completion due to the RB bankruptcy. The proposed settlement with the MH contractor is reflected in this CI revision. There is also a need for additional funding to complete the fire protection work due to unforeseen delays by the main MH contractor. ($7.0M)

Waste Water Treatment: Remediation of the primary clarifier foundations and lower tank sections resulted in unplanned expenses. In addition, previously assumed back charge costs associated with outside engineering services have been limited by contractual terms, necessitating additional funding. ($3.7M)

Balanced Draft/Boiler Modifications: The current forecast, and this request, includes increased costs for unanticipated extra work associated with the Trona modifications for controlling SO3 emissions and extra work associated with the balanced draft modifications to the boiler. The costs associated with the remediation of the precipitator outlet plenums associated with the balanced draft stiffening are also included in this request. ($16.6M)

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Miscellaneous Site Support: AEP Services have increased in proportion to the support required to interface with the ongoing work, including temporary heat, grouting and general site support transportation and sanitary services. ($3.1M)

Explanation of CI Revision Version 3

On March 4, 2006, the Mitchell project experienced a fire in the stack being constructed as a part of the Mitchell FGD / SCR / Associated projects CI. The fire severely damaged the construction of the stack liner that had taken place on the stack. In addition, the fire also had significant impacts on the progress of all work taking place at Mitchell as the entire site was affected by schedule delays, site restrictions, and re-sequencing of work activities.

As a result of this fire certain costs associated with the recovery from the stack fire were presented to AEP's Risk & Insurance Management department for recovery under AEP's applicable insurance policies. From March 2006 through November 2006, the Mitchell Project Management team, along with support from Project & Field Services and Generation Business Services, worked to identify "known" impacts from the stack fire event and provide information to Risk & Insurance Management for review.

On December 5, 2006, Project & Field Services and Generation Business Services were notified by AEP's Risk & Insurance Management department that after review of the information provided for recovery under AEP's insurance policies, there were a considerable number of items that were not subject to recovery under any of AEP's applicable insurance policies.

The following excerpts were taken from the notification received from AEP's Risk & Insurance Management department:

> "After review and discussion of the cost items pertaining recovery from the Mitchell stack fire with GBS, P&FS, and our adjusters at Crawford, Risk & Insurance Management has identified certain expense items that are not insured under the AEP corporate property insurance policy, as written at the time of the loss."
>
> "AEP's insurance covers direct physical loss or damage to property in the course of construction for the interest of contractors, where provided by contract, and for the interest of AEP. Additionally, our insurance provides coverage for expediting expenses as it relates to damaged property; to demolition or increased cost of construction incurred when the enforcement of any law or ordinance regulates the repair or reconstruction of damaged and undamaged property; debris removal expense due to physical loss or damage; decontamination and clean up expense where the physical loss or damage is paid or agreed to be paid by the Insurer; fire brigade charges and extinguishing expense resulting from physical loss or damage insured by the policy."
>
> "Extra Expense and Delay in Start-Up costs and the associated expense to reduce these types of costs are not insured."
>
> "A substantial element of the costs was consequential delay expense incurred by AEP for undamaged or un-constructed project work under several contracts: B&W; MJ Electric; Chapman; Enerfab. In order for AEP to remain on schedule, decisions were made to increase the weekly length of labor hours incurred per week."
>
> "Another aspect of the information include AEP internally incurred and anticipated costs. Although these are not completely supported, adequate discussion to gain an understanding surrounding the nature of these items indicates they are not insured expenses."
>
> "Lastly, this submittal has an estimate under the Pullman section for additional amount of $8,700,000. Of this amount, $6,000,000 represents additional cost to undamaged and un-constructed project work yet to be completed. This additional cost is due to congestion in the work area and completing the work on the second liner after the first liner is operational."

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After evaluating the "known" costs that have been identified by AEP's Risk and Insurance Management as "Not Subject to Insurance Recovery" ($16.5M), as well as pending or future costs that may be incurred by AEP associated with the stack fire, this CI Revision is being routed for $25.0M (Units 1 & 2 Combined) to cover all costs associated with this event. Although not covered by insurance, AEP has incurred (and continues to incur) a significant cost impact to the project as a result of the stack fire. These costs were clearly not foreseen when the original CI was prepared.

Explanation of CI Revision Version 2

- Please reference the attached presentation for an overview of the CI revision, project update, and the cost containment strategies that are in place on the project.
- Two significant and unforeseen events have occurred since the Phase III CI Authorization was approved.

  √ The primary civil / foundation contractor, Ragnar Benson, Inc., declared bankruptcy while working on the project and ceased all work activity.
    - This event impacted foundation completion, delayed critical path, compressed the overall schedule, increased site peak manpower requirements, and created significant site logistics issues.
    - In order to attempt to maintain schedule and, to the extent possible, mitigate impacts on other contractors, AEP was required to complete the remaining scope of work abandoned under Ragnar Benson's firm price contract by utilizing on-site contractors at an increased cost to the project.

  √ The Mitchell stack fire incident had a significant impact on the execution of the project. The project experienced a loss of progress, sixty (60) day schedule impact, re-sequencing of work activities, and significant schedule compression.

- FGD / SCR

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  √ The associated projects were originally budgeted based upon engineering concepts. Design details were developed during outage inspections and with integration of SCR / FGD components. These design details were completed in 2005, subsequent to the Phase III CI Authorization.

  √ The completion of engineering and labor contracting on the associated projects occurred in 2006, after the construction market began to reflect considerable market escalation.

  √ In the Phase III CI Authorization, a preliminary $20 million "placeholder" was budgeted for Purge Stream Waste Water Treatment, based on limited industry benchmarking. Subsequent site and process specific engineering and design work, coupled with the securing of valid proposals for installation labor and

equipment have been completed. With specific management focus, oversight and control, the forecasted cost of this project is still expected to be $40M, double the preliminary estimate used in the Phase III CI Authorization.

√ The results of the impacts noted above, mitigated by direct management intervention and strict control culminates in the associated project's direct cost forecasts being limited to approximately 38% from the Phase III CI authorization.

Project Justification

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  In January 2004, AEP reanalyzed the compliance plan in light of the proposed EPA clean air interstate rule (CAIR) and the mercury rules (proposed in December 2003) and reached an identical conclusion. The Mitchell Unit 2 WFGD and SCR were again found to be an economic decision.

- In January 2005, updated capital costs and fuel pricing were entered into the WFGD model and Mitchell Plant was again selected for scrubbing as were retrofits necessary to burn low-cost high sulfur coal as part of AEP's least cost compliance plan. In addition, under all the scenarios analyzed, the fuel and operating costs of Mitchell Unit 2 plus the WFGD investment (incremental capital) and additional O&M costs were well below market prices for power now and projected in the future, indicating that the investment in Mitchell was sound and robust relative to market alternatives.

- In order to meet the Mitchell Unit 2 WFGD/SCR 2006 in-service date, Phase III CI funding is required to continue and complete detailed engineering, design, scheduling, environmental planning, permitting, procurement, and construction to obtain operational WFGD and SCR systems at Mitchell. Phase III includes the erection of the WFGD, SCR and Balance of Plant (BOP) equipment and system startup.

- Specifically, Phase III will build upon the engineering and budgetary cost estimates from Phase II and continue with detailed engineering, design and construction. Construction labor Request for Quotation (RFQ) Packages were issued for competitive pricing and have become the basis of the Phase III requested labor funding for the WFGD project. A firm price for the SCR construction has been established, also through the use of competitive pricing.

- Phase III funds the selected A/E through completion of detailed engineering, design, and construction in 2007. Phase III also funds the selected WFGD and SCR OEMs to continue

design and equipment selection, to support the construction and in-service schedule. Funding for Phase III also supports internal AEPSC engineering, design, air permitting efforts, project management and construction services through completion of the project.

Other Alternatives Considered

- The SO_2 Compliance Plan has evaluated several alternatives such as the procurement of SO_2 allowances on the open market and/or fuel switching, but these alternatives will not provide the amount of SO_2 allowance required to support AEP's coal-fired electrical generation fleet.

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Conclusion

- This request for funding to complete engineering, design, procurement, construction, and start-up is required to support the WFGD and SCR schedule.

- This strategy supports the construction of WFGD and SCR systems at Mitchell Unit 2 for operation December 2006.

Associated / Future Projects

The AEP Fleet Compliance Plan, to address emissions regulations in the most cost-effective manner, relies on the efficient and reliable operation of the controlled Units. The associated projects identified below are intended to provide greater operational flexibility in this area and addressing overall reliability. The complexity of the associated projects and their interaction between the WFGD and the SCR requires continuing review to optimize scope, costs and schedule. These projects are consistently selected as a key part of the low cost compliance plan through MECO model analysis.

Steam generator additions to allow the use of the most economic high sulfur coal have been analyzed as a part of the WFGD project. The following associated projects are included in Phase III.

- **Balance Draft Conversion** – The installation of WFGD necessitates the implementation of new fans to overcome the additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balanced draft condition). Converting to balance draft design concurrent with a WFGD retrofit enables the Unit to combust high sulfur lower cost coal, consistently provides a less hazardous work environment, mitigates reduction in unit availability and reduces potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - A portion of the SO_2 generated during coal combustion is oxidized to SO_3 in the steam generator and further oxidized in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from both the steam generator and SCR. Without additional controls, the stack SO_3 levels are projected to exceed the stack targeted control range and could contribute to a blue plume opacity in the flue gas exiting the stack. The installation of a magnesium hydroxide slurry injection system into the upper furnace of the steam generator will reduce SO_3 exiting the boiler. The SCR will be designed to utilize low SO_2 to SO_3 conversion rate catalyst to minimize the amount of SO_3 converted in the SCR. The remaining SO_3 levels will be reduced to the control range via use of the existing ammonia injection system.

- **Unit Controls Modernization** – The installation of WFGD and SCR technologies will utilize a state of the art control system. This new, modern DCS system will be integrated into the existing unit controls, which will be incrementally modernized so as to make this work feasible. "Stand-alone" controls for the WFGD and SCR are not desirable.

- **Fuel Blending Capabilities** – On-site blending capability adds significant flexibility for the procurement of the most economic fuel. The economies of burning high sulfur coal have been analyzed as part of the WFGD project and are supported by the economic models. Mitchell plant has the tunnel and chute capacity and a radial stacker that will accommodate a blending operation. There are conveyors that would need to be added and/or upgraded to allow blending.

- **Steam Generator Additions** – Building on the fuel flexibility benefits, for Mitchell Plant to combust coals with sulfur contents as high as 4.5#/MBtu, the steam generator will require some changes, including installation of a new rear wall arch, additional furnace slag control devices (water cannons and/or blowers), furnace overlay to mitigate increased furnace corrosion, and boiler instrumentation upgrades.

- **River water Makeup Pump Upgrades** - The water demands of the WFGD and SCR systems exceed the existing capacity of the river water makeup system. Review of various options to increase system capacity has determined that the most economic approach is to replace the existing pumps and motors with higher flow capacity pumps/motors. This will assure reliable water supply for plant needs as well as the WFGD and SCR.

- **Purge Stream Water Treatment** – Initial evaluation of the potential purge stream water contents indicates that treatment may be required. Further studies are in progress to determine the extent of treatment if any, which may be required. In order to maintain the current schedule, a preliminary estimate of $20 million is allocated to fund this portion of the work. This number was determined from benchmarking the industry and input from the AE and will be accurately determined late in the second quarter of 2005.

Additional Information

Regulatory Issues

- Existing regulations under Title IV of the Clean Air Act, as well as regulations currently under development by the U.S. EPA, along with other alternatives to the Clean Air Act being considered by Congress such as Clear Skies and the Carper Bill, will require AEP to reduce emissions of SO_2 in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. U.S. EPA proposed in December 2003 regulation of interstate air quality that, if promulgated, will require significant additional SO_2 and NO_x emission reductions beginning in 2010. U.S. EPA also proposed in December 2003 regulation of mercury emissions from coal-fired power plants. Mercury emission reductions can be achieved with a combined SCR and WFGD system. In addition to these proposed regulations, the existing Title IV acid rain control program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

Background Information

- The WFGD technology is targeted to be capable of 98% SO_2 removal efficiency. This level of removal will allow for an expected 95% reduction in annual emissions during all modes of operation. The reagent will be limestone, and the technology will provide the operational flexibility to produce a wall-board quality gypsum by-product. The WFGD design criteria provide maximum fuel flexibility by allowing for the burning of high sulfur coal.

- The WFGD design basis for this unit includes provisions for adding future emission control equipment for reduction of mercury and possibly other emissions without relocation of equipment.

This approach will allow for implementation of current emerging technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

- The SCR system will be designed for a 90% NOx removal rate with an allowable maximum ammonia slip of 2 ppmv (at 3% O_2) and a design catalyst life that minimizes the life cycle costs. A urea to ammonia conversion system will be used to supply the SCR reactors with reagent.

Project Contacts

Contact	Name	Telephone
Project Manager	Ed Gilabert	(614) 716-1765
Requisition Detail Provider	William King	(614) 716-1791

Date September 13, 2013

Company	CI/LI/CPP/Program Number	Version
Ohio Power Company	000023038	1

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verfied funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	DEA 9/20/13		DEA 9/20/13

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
	D. Lee	9/4/2013	
	P. Vegas	9/9/2013	
	C Patton	9/13/2013	
	G. Pauley	9/13/2013	
1	D. Adams	NGA 9/17/13	
2	D. Lynch	DBK 9/20/13	
	L. L. Dieck		
	B. X. Tierney		
	M. C. McCullough		
3	C. Zebula	CBZ 9/20/13	
	R. P. Powers		
	N. K. Akins		
	Buckeye Power Approval		
4	Darryl Lynch - 28th floor Ext 1142		
		9/24/13	Approved in PeopleSoft
		Sept 2013	Month Included in Board Package

Alternate CP&B Contacts:
Jenifer Fischer - 28th Floor - Ext 3032

Scanned File Name: OPCo 000023038.pdf

Capital Improvement Approval Requisition

Company: Ohio Power **Version** 1

Project : **000023038 - Mitchell 1& 2 Mercury Air Toxics Standard (MATS) Compliance Monitoring**
Moundsville, West Virginia

Description: This requisition request funds to install new mercury (Hg) monitors and make improvements to existing Hg monitors in order to comply with the monitoring and reporting requirements outlined in Mercury and Air Toxics Standard. MATS requires monitoring and reporting of particulate matter (PM), acid gases (AG) and Hg emissions from coal fired generating units.

Compliance with the PM requirements will be achieved by conducting quarterly PM emission flue gas testing. Compliance with the AG requirements will be achieved on the Units equipped with high efficiency scrubbers using their existing SO_2 monitoring systems. All other units will require quarterly Hydrogen Chloride emission flue gas testing to demonstrate compliance with the AG requirements. Testing can be performed by an Environmental testing company as part of the other plant RATA activities. New sorbent trap Hg monitors will be installed and improvements will be made to existing sorbent trap Hg monitors for Hg compliance reporting. In addition, the existing real time continuous Hg monitors will either be upgraded or replaced to allow for optimization of unit operation to ensure compliance with the new 30-day rolling average Hg emission limit.

This project will install new Hg monitors and improvements to existing Hg monitors on two stacks: Mitchell 1 and Mitchell 2.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$ -	$ 1,685,275	$ 1,685,275

Cash Flow:

	Prior Years	2013	2014	Future Years	Total
Capital	$ -	$ 149,704	$ 1,443,142	$ 92,429	$ 1,685,275
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ -	$ 149,704	$ 1,443,142	$ 92,429	$ 1,685,275
Associated O&M	$ -	$ -	$ 87,790	$ -	$ 87,790

Start Date: 9/1/2013 **Completion Date:** 6/1/2015 **In Service Date:** 4/16/2015

Regulatory Cost Recovery: Recovery is subject to the outcome of the asset transfer cases.

Funding: **Included in IRC Presentation** Yes **Project Funded** Yes **Offset Source** OPCO - G

Requested future year funds are included in the last official Forecast.

Approved By: D. Lee/P. Vegas/G. Pauley/C. Patton/C. Zebula **Approved On:** 9/20/2013

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	-	-	-
This Submission	1,685,275	-	1,685,275
Total	**$ 1,685,275**	**$ -**	**$ 1,685,275**

2013 Direct Cost Funding		Offset Source and Amount
In Forecast	$ -	*OPCO 181 FODA $84,773 ; OPCO 181 INCCAPINV $59,996*
Offset	$ 144,739	

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	SVP, Business Unit	Lee, D.	See attached electronic approval	09/04/13
amt ≤ $ 10m	Opco President	Patton, C.	See attached electronic approval	09/13/13
amt ≤ $ 20m	EVP Energy Supply	Zebula, C.	CKZebula	9/20/13
CP&B Review	Manager, Capital and Lease Improvements	Lynch, D.	DHynch	9/20/13

Project Contacts

Contact	Name	Telephone
Project Manager	Wiley Elliott	614 716 1790
Requisition Detail Provider	George Jonda	614 716 2715

Capital Improvement Approval Requisition

Project Justification

This project will install the improvements to allow compliance with the monitoring and reporting requirements of the Mercury and Air Toxics Standards (MATS).

This project proposes to install new Hg monitors and improvements to existing monitors at two (2) units in the AEP fleet.
These units are: Mitchell 1 and Mitchell 2.

Other Alternatives Considered

A single trap system was considered, however MATS requires that the startup/shutdown and operational conditions be monitored separately. It would be impracticable to perform this monitoring with a single system. Improvements to the existing Hg systems provide a cost effective solution for monitoring of the startup/shutdown and can be automated.

The use of real time continuous Hg monitors for compliance purposes was eliminated as an option due to the past experience with this type of equipment. Additionally, not installing a continuous monitor and only using Sorbent Trap Mercury Monitoring was also considered.

Testing of mercury emissions during the latter half of 2012 and 2013 have provided data that mercury emissions are highly variable and quite sensitive to plant operating conditions. Use of sorbent trap only systems would result in a delay in knowledge of mercury emissions. Considering a 7 day trap sampling time and the time necessary to analyze the traps, if a condition of high emission was occurring, the ability to take corrective action sufficient to maintain the emissions below the rolling 30 day average may be very difficult. A continuous system will provide real time data to plant operations so that correction actions can be made as soon as possible.

Conclusion

It is recommended new sorbent trap Hg monitors be installed and improvements made to the existing sorbent trap Hg monitors to comply with the requirements of MATS. In addition, the existing real-time continuous Hg monitors are to be either upgraded or replaced to provide real-time data to plant operations so that corrective actions can be made as soon as possible to ensure compliance with the new 30 day rolling average Hg emission limit.

Associated/Future Projects

Separate capital improvement requisitions will be submitted for APCO (Amos 1, 2, 3, and Mountaineer 1), Buckeye (Cardinal 2,3), SWEPCO (Turk 1) and OPCO (Cardinal 1, Conesville 4, 5&6, Gavin 1, 2, and Amos 3 (2/3 funding)). Additionally, the scope of the environmental upgrade projects for Northeastern 3, Flint Creek, Oklaunion, Rockport, Welsh 1, Welsh 3 and Pirkey are to include the scope necessary for MATS compliance monitoring.

The remaining coal fired units in the fleet are scheduled for shutdown prior to their compliance dates.

Date May 2, 2012

Company	CI/LI/CPP/Program Number	Version
Appalachian Power and Ohio Power	WWT4HGRED	3

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	JLF 5-2-12		JLF 5-2-12

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
1	D. Lynch	5/3/12	
2	L. L. Dieck	5/8/12	
	C. Zebula		
	B. X. Tierney		
	M. Heyeck		
	B. D. Radous		
	S. Burge		
	L.J. Weber		
3	M. C. McCullough	MCM 5/4/12	
	D. E. Welch		
	R. P. Powers		
	L. Barton		
	Buckeye Power Approval		
4	N. K. Akins	5/7/12	
5	Jenifer Fischer - 28th floor Ext 3032		
		5/7/12	Approved in PeopleSoft
		May 2012	Month Included in Board Package

Alternate CP&B Contacts:
Cathy Warchal - 28th Floor - Ext 1347

Scanned File Name: APCo and OPCo WWT4HGRED Version 3.pdf

Capital Program Approval Requisition

Company: Appalachian Power Company and Ohio Power Company — Version 3

Project: WWT4HGRED Revision - Mercury Reduction in the FGD Chloride Purge Stream - Phase 2
Various Generating Plant Locations

Description: In order to meet the new monthly average mercury compliance limits established as the various plants National Pollutant Discharge Elimination System (NPDES) permits are renewed, new mercury Reduction technology must be installed.

Version 1 requested funding to initiate a program of mercury reduction in 2009 and 2010 at five generating stations to meet current environmental regulatory requirements. Phase I involved the installation of Organo-Sulfide chemical treatment on the Chloride Purge Stream (CPS) in the Waste Water Treatment Plant (WWTP) at Mitchell. Funding was also included for the preliminary engineering and procurement for a similar system at Mountaineer, and feasibility engineering and pilot testing for an in-pond chemical treatment system at Mitchell for additional mercury reductions.

Version 2 requested Phase 2 funding of the project which included the engineering, design, procurement and installation of WWT CPS mercury reduction systems at the Cardinal, Conesville, Amos and Mountaineer plants. Funding for permanent in-pond mercury reduction systems at the Mitchell, Amos and Mountaineer plants was also requested as the pilot testing at Mitchell was successful in further reducing mercury concentrations.

Reason for Revision: This is a revision to Phase 2, which is the final phase of the project. This Program Improvement Requisition revision is requesting funds for modifications to the Amos portion of the program. The Amos Mercury Reduction Systems were placed in service on 1/25/11. The installed systems do not reliably and consistently achieve compliance limits. A corrective action plan was submitted in June 2011 and approved by the WV DEP on 9/9/11. This plan includes adding 3 permanent chemical injection skids, replacing the clarifiers, separating train operation, installing a river effluent diffuser, and operation and maintenance improvements to be in service by 12/31/12.

Authorization Amount:

Company	Previously Approved Amount	This Submission	Total Amount to be Authorized
OPCO	7,017,743	2,263,232	9,280,975
APCO	9,225,100	4,933,771	14,158,871
Total*	**$ 16,242,843**	**$ 7,197,003**	**$ 23,439,846**

*Total Amount to be Authorized excludes $1.3M Buckeye Power portion of Cardinal Project.

Cash Flow:

	Prior Years	2012	2013	Future Years	Total
Capital	$ 14,326,539	$ 9,113,307	$ -	$ -	$ 23,439,846
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 14,326,539	$ 9,113,307	$ -	$ -	$ 23,439,846
Associated O&M	$ -	$ -	$ -	$ -	$ -

Start Date: 8/1/2009 **Completion Date:** 12/31/2012 **In Service Date:** Various through 12/31/2012

Regulatory Cost Recovery:

Appalachian Power Company - Generation -$14.16M (60%)

- $6.65M (47%) APCo VA Base Rate Case Filing, TYE 12/31/12 w/cost projections through 1/31/15, effective 1/31/14; or through deferral of expenditures for recovery under the Environmental Rate Adjustment Clause (E-RAC) to be filed TBD, with cost projections through TBD.
- $6.09M (43%) APCo WV Base Rate Case Filing, TYE 12/31/11, with cost projections through 12/31/12, effective 7/1/13
- $0.85M (6%) KgPCo purchased power pass-through from APCo under three-year settlement agreement phase-in of generation rates through 12/31/11 remains in effect post-2011 until new agreement is in place.
- $0.57M (4%) FERC Annual Formula Rate Update, TYE 12/31/12, effective 6/1/13

Ohio Power Company – Generation - $9.28M (40%)

- $8.91M (96%) Costs through 2011 will be recovered under generation rates established by the ESP Order of March 2009. Upon approval from State and Federal regulatory authorities, Ohio Power Company's generation fleet will transition into a competitive market. Currently, base generation revenues authorized by the PUCO (approved in March 2009 ESP) are not cost-of-service based, so there is no incremental cost recovery mechanism for new capital investments. As such, new investment carrying costs are deemed a cost of business offsetting ESP authorized revenues.
- $0.37M (4%) Allocated to WPCo and recovered in current demand charge effective 1/1/10

Funding: **2012 Control Budget** *(included in IRC Presentation)*: Yes — **Offset Source**: N/A

Requested future year funds are included in the last official Forecast.

Approved By: S. Burge/C. Patton/J. Hamrock/ M. McCullough/N. Akins **Approved On:** 5/7/2012

Capital Program Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	16,242,843	-	16,242,843
This Submission	7,197,003	-	7,197,003
Total	**$ 23,439,846**	**$ -**	**$ 23,439,846**

2012 Direct Cost Budget Funding			Budget Offset Source and Amount
In Budget	$	8,205,000	*APCO 215 & OPCO 181 FODA*
Budget Offset	$	38,284	

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	SVP, Business Unit	Burge, S.	See electronic approval attached	4/10/2012
amt ≤ $ 10m	Opco President	Hamrock, J. Patton, C.	See electronic approval attached	4/23/12 4/11/12
amt ≤ $ 20m	EVP & COO/EVP	McCullough, M.		5/4/12
amt ≥ $ 20m	President & CEO	Akins, N.		5/7/12
CP&B Review	SVP, Corporate Planning & Budgetting	Dieck, L.		5/3/12

Project Contacts

Contact	Name	Telephone
Project Manager	Juliet Majtenyi / Deinse Lantzy	200-2293 / 200-1784
Requisition Detail Provider	George Jonda	200-2715

Capital Program Approval Requisition

Component CI's

CI Number	Description of Work	Previously Approved		This Submission		Total Authorized		
		Capital	Removal	Capital	Removal	Capital	Removal	Total
000016404	Amos FGD WWT Hg	1,926,046		6,053,988		7,980,034		7,980,034
000016406	Mountaineer FGD WWT Hg	2,492,031		(1,354,295)		1,137,736		1,137,736
000019682	Mountaineer Perm In-pond Treatment	2,706,753		(465,569)		2,241,184		2,241,184
000019683	Amos Perm In-pond Treatment	2,100,270		699,647		2,799,917		2,799,917
				-				-
	Appalachian Power	**9,225,100**	-	**4,933,771**	-	**14,158,871**	-	**14,158,871**
000016400	Mitchell FGD WWT Hg	2,170,480		(140,579)		2,029,901		2,029,901
000016402	CD FGD WWT Hg	845,730		(128,564)		717,166		717,166
000016405	Amos FGD WWT Hg	562,698		2,955,421		3,518,119		3,518,119
000018350	CV4 FGD WWT Hg	1,105,971		(514,765)		591,206		591,206
000019681	Mitchell Perm In-pond Treatment	1,718,121		(513,914)		1,204,207		1,204,207
000019684	Amos Perm In-pond Treatment	614,743		605,632		1,220,375		1,220,375
				-				-
	Ohio Power	**7,017,743**	-	**2,263,232**	-	**9,280,975**	-	**9,280,975**
000016403	CD FGD WWT Hg (BPCo)	1,667,680		(354,386)		1,313,294		1,313,294
	Buckeye Power*	**1,667,680**	-	**(354,386)**	-	**1,313,294**	-	**1,313,294**
Grand Total*		**$ 17,910,523**	**$ -**	**$ 6,842,617**	**$ -**	**$ 24,753,140**	**$ -**	**$ 24,753,140**

*Grand Total includes Buckeye Power Component CI 000016403. This amount is excluded from Amount to be Authorized on Summary Tab.

AEP Grand Total		**$ 16,242,843**	**$ -**	**$ 7,197,003**	**$ -**	**$ 23,439,846**	**$ -**	**$ 23,439,846**

Capital Program Approval Requisition

Reason for Revision

This Program Improvement Requisition requests the funding for Modifications to the Amos portion of the program. Amos Mercury Reduction Systems were placed in service on 1/25/11. The installed systems do not reliably and consistently achieve compliance limits. A corrective action plan was submitted in June 2011 and approved by the WV DEP on 9/9/11. This plan includes adding 3 permanent chemical injection skids, replacing the clarifiers, separating train operation, installing a river effluent diffuser, and operation and maintenance improvements to be in service 12/31/12.

Version 2 Project Justification

The current NPDES permits for Mitchell, Mountaineer, Amos, Cardinal, and Conesville Plants contain water quality effluent limitations for mercury that are required to be met during 2010 to 2011. At these facilities, the mercury limits have been established at or below 12 ppt at their outfalls.

Pilot testing of mercury reduction technologies was conducted at Mountaineer Plant from July 2008 to December 2008. The most significant finding of the pilot test was that the mercury being discharged from the Chloride Purge Stream (CPS) in the Waste Water Treatment Plant (WWTP) could be significantly decreased (~80-90% reduction) by injecting an organo-sulfide chemical with an optimized coagulant feed upstream of the WWTP primary clarifiers. The increased mercury removal rate is primarily due to the capture and settling of mercury bound to fine suspended solid particles in the CPS effluent. Using Mitchell Plant as an example, the existing CPS WWTP discharge contains mercury concentrations in the range of 1000 - 2000 ppt. With the chemical optimization in the CPS WWTP, it has been demonstrated that mercury concentration in the effluent stream can be reduced to < 200 ppt, but could not achieve the required <12 ppt.

As noted above, mercury reduction at the CPS WWTP alone was not sufficient to comply with NPDES limits at pond outfalls. Mitchell, Mountaineer, and Amos will require mercury reduction in the other streams that enter the pond system. The removal mechanism for mercury for in-pond treatment is similar to the organo-sulfide and coagulant injection at the CPS WWTP where fine particles containing mercury will settle out in the ponds and are retained in the sludge rather than being discharged to the permitted outfall. In-pond treatment requires chemical injection systems, a recirculation system for coagulant dilution, and potential modification of the ponds to improve chemical distribution and increase effective retention to enhance settling of solids. A temporary in-pond treatment pilot test at the Mitchell Plant has demonstrated reduction in mercury to the 12 ppt level. Based on these results, permanent in-pond treatment systems at Mitchell, Mountaineer and Amos will be installed prior to the permit deadlines.

In-pond treatment at the Cardinal and Conesville Plants is not practical due to differences in the plant configuration. Due to the location of the outfalls, effluent is diluted and at this time it is expected permit requirements will be met. If additional mercury reduction is required it will be addressed using different technology or modifications.

Installation of the organo-sulfide and coagulant injection systems in the CPS WWTP and bottom ash pond is in progress at the Mitchell Plant with a compliance operational date of 5/4/2010. The compliance operational dates are 3/9/2011 for Amos Units 1-3, 12/1/2010 for Cardinal Units 1-3, 12/13/2010 for Conesville U4, and 7/10/2011 for Mountaineer.

Program funding is being requested for the second phase of this program:

Phase II: $13.0M

a. Complete engineering, design, procurement and installation of organo-sulfide and coagulant chemical treatment of the CPS in the WWTP at the Mountaineer, Amos, Conesville, and Cardinal Plants.
b. Complete engineering, design, procurement and installation of organo-sulfide and coagulant chemical injection systems for in-pond treatment at the Mitchell, Mountaineer, and Amos Plants. This includes potential pond configuration changes to enhance chemical distribution and solids sedimentation.

Capital Program Approval Requisition

Justification for Version 1

Phase I involves the installation of Organo-Sulfide chemical treatment on the Chloride Purge Stream (CPS) in the Waste Water Treatment Plant (WWTP) at Mitchell Plant. Also included will be preliminary engineering and procurement for a similar system at Mountaineer and pilot testing for an in-pond chemical treatment system at Mitchell. Phase II would install Organo-Sulfide chemical treatment at four other plants in 2010.

The current NPDES permits for Mitchell, Mountaineer, Amos, Cardinal, and Conesville Plants contain water quality effluent limitations for mercury that are required during the period 2010 to 2012 (compliance dates differ for each facility). At most of these facilities, the new mercury level requirement is greatly reduced to around 12 ppt. Installation and operation of wet FGD systems presents a new potential source of mercury to the pond systems.

Pilot testing of mercury reduction technologies was conducted at Mountaineer Plant from July 2008 to December 2008. The most significant finding of the pilot test was that the mass of mercury being discharged from the Chloride Purge Stream (CPS) in the Waste Water Treatment Plant (WWTP) could be significantly decreased (~80-90% reduction) by injecting an organo-sulfide chemical with an optimized coagulant feed in the WWTP clarifier. The increased mercury removal rate is primarily due to the capture and settling of mercury bound to fine suspended solid particles in the CPS effluent. Using Mitchell Plant as an example, the existing CPS WWTP discharges mercury concentrations in the range of 1000 - 2000 ppt. With chemical optimization it would be reasonable to expect that the mercury concentration in the effluent stream would be < 200 ppt, but not achieve the required <12 ppt. Mitchell Plant's NPDES permit requires that organo-sulfide (or a similar functional coagulant) construction at the FGD WWTP start no later than November 4, 2009. Organo-sulfide chemical costs per site will range from $50,000 to $100,000 per year.

Installation of the organo-sulfide injection system in the CPS WWTP is planned in 2009 at Mitchell Units 1&2 and by mid 2010 at Mountaineer Unit 1. The compliance operational dates are 5/4/2010 and 7/10/2011 respectively. The installation for Mitchell and Mountaineer is being accelerated to allow design optimization in the case of Mitchell and to replace the temporary system currently in operation at Mountaineer. The compliance operational dates are 1/9/2011 for Amos Units 1-3, 12/1/2010 for Cardinal Units 1-3 and 12/31/2010 for Conesville U4.

In conjunction with the installation of the organo-sulfide injection system in the CPS WWTP at Mitchell Units 1&2, a pilot test will be conducted in the Mitchell second bottom ash pond. Mercury reduction at the CPS WWTP alone will not be sufficient to comply with NPDES limits at pond outfalls. Mitchell, Mountaineer, and Amos will require mercury reduction in the other streams that enter the pond system. Given the typically large flow rates of these streams, such as ash transport, plant sumps and cooling tower blowdown; it is not practical to treat these streams individually due to the large space requirements to treat the large flow rates individually. The targeted option is to treat all of the streams using an in-pond treatment. The removal mechanism for mercury for in-pond treatment is similar to the organo-sulfide injection at the CPS WWTP in that fine particles containing mercury will settle out in the ponds and be retained in the sludge rather than being discharged to the permitted outfall. In-pond treatment for mercury reduction will require the addition of organo-sulfide or similar chemicals and coagulants in the pond complex, and modification of the ponds to improve chemical distribution and increase effective retention to enhance settling of the solids. In-pond treatment at Cardinal and Conesville is not practical due to differences in the plant configuration. If additional mercury reduction is required it will be addressed using different technology or modification. Additional chemical costs for in-pond treatment are not known at this time, but could approach $3M per year per site.
Program funding is being requested in two phases due to the uncertainty of the costs associated with the developing technology. The two phases are broken out as:

1. Phase I – 2009 and early 2010 - $4.9M
   a. Engineering, design, procurement and installation of Organo-Sulfide chemical treatment of the Chloride Purge Stream (CPS) in the Waste Water Treatment Plant (WWTP) at Mitchell Units 1&2 in 2009.
   b. Begin engineering, design and material procurement for Organo-Sulfide chemical treatment of the CPS in the WWTP for Mountaineer, Amos, Conesville and Cardinal.
   c. Perform feasibility engineering and pilot testing for an in-pond chemical treatment system to supplement the CPS WWTP system at Mitchell.
2. Phase II – 2010 - $12.3M
   Complete engineering, design, procurement and installation of Organo-Sulfide chemical treatment of the CPS in the WWTP at Mountaineer, Amos, Conesville and Cardinal.

Capital Program Approval Requisition

Justification for Version 1 (continued)

The Phase II CI revision will be submitted around February, 2010. Actual costs associated with Phase 1 will be used to assist in determining the final expected costs since the Program is currently in the early Engineering and Design phase.

Other Alternatives Considered

Alternatives to Organo-Sulfide chemical treatment in CPS WWTP:

Pilot testing of mercury reduction technologies conducted at Mountaineer during 2008 included evaluation of the following technologies: ultrafiltration; mercury selective ion-exchange resin; and bioreactors. The direct equipment costs of these technologies range from $1.2million to $5.45million for a 350gpm system. Installation costs, balance of plant upgrades and overheads would greatly inflate these numbers. Additionally, each technology would require more footprint space than is currently available in the existing CPS WWTP buildings. The success of these technologies to reliably reduce mercury in the CPS WWTP to levels below 12 ppt was not demonstrated during the Mountaineer Pilot test. The ultrafiltration units employed by two of the vendors would not remain in service for extended time periods. The test units failed within two weeks of operation. While ion-exchange resin and bioreactor technologies showed promise of being able to produce an effluent mercury concentration of less than 12 ppt each technology requires a fully operational ultrafiltration unit to remove suspended and colloidal mercury. Further pilot testing is required to find a filtration technology that may provide reliable service in addition to removing suspended and colloidal mercury from the effluent stream. The recommendation to install organo-sulfide chemical treatment of the CPS WWTP is based upon observations that an 80-90% reduction of mercury may be reliably achieved by the application of this technology.

The primary O&M costs associated with the chemical treatment in the CPS WWTP are the organo-sulfide and coagulant chemical costs. Annual costs are expected to range from $50,000 to $100,000 at each site.

Alternatives to In-Pond treatment:

Alternative technologies to in-pond treatment that were considered are identical to those listed for the CPS WWTP. The most significant difference is that individual treatment of mercury containing streams entering the pond complexes have combined flowrates in excess of 6 million gallons per day (MGD). This is a flowrate approximately 12 times higher than the flowrate used for the cost basis of the alternate technologies considered for the CPS WWTP. A large volume flowrate requires a new treatment facility with a footprint much larger than any plant currently has available. In-pond chemical treatment has shown significant promise in laboratory testing and given the space constraints of the alternatives it may be the only viable option for Mitchell, Mountaineer and Amos Plants. The in-pond pilot test at Mitchell confirmed laboratory testing and appears to be a cost effective means of further reducing mercury concentrations at Mitchell, Mountaineer, and Amos pond outfalls.

Similarly, the primary O&M costs with the in-pond treatment at Mitchell, Amos and Mountaineer will be the organo-sulfide and coagulant chemical costs. Costs will be dependant on the pond inflows, which can range between 3 to 9 millions gallons per day. An average annual cost of $600,000 is expected at each site.

No Action Option:

The option of taking no action was considered. Taking no action would result in violations of effluent limitations and other provisions of the facility's National Pollutant Discharge Elimination System (NPDES) permit. These violations are subject to enforcement action by the state permitting agency or U.S. EPA which can include civil penalties allowed under the Clean Water Act of up to $32,500 per day per violation. More significant penalties exist for knowing violations of the permit.

Conclusion

To meet the NPDES permit requirements, mercury reduction technologies must be installed.

Capital Program Approval Requisition

Associated / Future Projects

The latest Mountaineer NPDES permit identifies three primary issues regarding effluent to the river – mercury, selenium, and storm water metals concentration. The selenium issue is being addressed via the installation of a bio-reactor technology. Storm water concerns continue to be evaluated but the source and treatment of metal concentrations has not been fully identified. The development of a storm water solution may potentially interact with the mercury and selenium reduction approaches.

Testing has demonstrated that installation of the organo-sulfide system in the CPS WWTP will remove approximately 80 to 90% of the mercury from the CPS, but will very likely not meet the NPDES permit requirements at the pond outfall due to the contribution of mercury from other plant sources. Preliminary testing has shown that the addition of chemicals in the second bottom ash pond at Mitchell can further remove mercury from the pond. Full pond testing with various chemicals is planned in 2009 to verify the initial small scale tests. If the results are consistent, chemical treatment of the ponds is planned for Mountaineer and Amos in 2011. The cost for the in-pond treatment systems could be approximately $9M per site, plus chemical costs approaching $3M per site per year.

Improvement modifications to reduce or prevent the introduction of mercury into power plant pond systems are proposed, and offer another solution to minimize mercury concentration at plant outfalls. An associated project involves the conversion to dry flyash for Conesville units 4, 5 and 6 under AEP Corporate Planning Proposal CVMERCMIT.

In parallel with engineering solutions to decrease mercury levels to permit-required discharge targets, Environmental Services is pursuing technical and administrative studies to either delay the mandated compliance date, or increase the applicable mercury limitations.

Regulatory Cost Recovery (or applicable heading)

(This page should only be used if there is not enough room on the Text Body page or if the Regulatory Cost Recovery language will not fit on the Summary Page.)

Date January 31, 2013

Company	CI/LI/CPP/Program Number	Version
Ohio Power	000019836	3

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	JLF 1-31-13		JLF 1-31-13

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
1	D. Lynch	2/4/13	
2	L. L. Dieck	2/1/13	
	B. X. Tierney		
3	M. C. McCullough		
	D. E. Welch		
4	R. P. Powers		
	L. Barton		
	Buckeye Power Approval		
5	N. K. Akins	2/7/13	
6	Jenifer Fischer - 28th floor Ext 3032		
		2-8-13	Approved in PeopleSoft
		Feb 2013	Month Included in Board Package

Alternate CP&B Contacts:
Cathy Warchal - 28th Floor - Ext 1347

Scanned File Name: OPCo 000019836 Version 3.pdf

Capital Improvement Approval Requisition

Company: Ohio Power Company **Version 3**

Project : **000019836 - Mitchell Units 1 and 2 Conversion to Dry Fly Ash Handling System - Phase 3**
Moundsville, WV

Description: This conversion is required to meet the new National Pollutant Discharge Elimination System (NPDES) selenium limits at the fly ash pond outfall and to assist in providing long-term disposal needs for Mitchell's fly ash. The project will convert Mitchell Unit's 1 & 2 fly ash handling systems from a wet slurry transport/disposal process to a dry ash handling system.

Version 1 of this CI completed Phase 1 activities to begin detailed engineering/design, environmental permitting, site preparation, foundation installation, and securing long lead time material procurements.

Version 2 of this CI completed Phase 2 activities to complete Phase 2 engineering/design, procurement of engineered equipment/materials, and ash silo erection.

Reason for Revision: This revision (Version 3) is required to authorize completion of Phase 3 engineering, procurement, construction, startup and commissioning to support a 3Q2014 in-service date.

The anticipated total cost of this conversion at completion of all phases is $138,199,581. This cost estimate incorporates the scope refinement and updated estimates for engineering, procurement, and construction that were developed during Phase 2.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$ 88,515,348	$ 49,684,234	$ 138,199,582

Cash Flow:

	Prior Years	2013	2014	Future Years	Total
Capital	$ 34,191,162	$ 73,798,813	$ 30,209,607	$ -	$ 138,199,582
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 34,191,162	$ 73,798,813	$ 30,209,607	$ -	$ 138,199,582
Associated O&M	$ -	$ -	$ -	$ -	$ -

Start Date: 3/1/2011 **Completion Date:** 8/13/2014 **In Service Date:** 8/13/2014

Regulatory Cost Recovery:

Ohio Power Company – Generation - $138.2M (100%)
Upon approval from State and Federal regulatory authorities, Ohio Power Company's generation fleet will transition to a competitive market. Equal shares of Mitchell Plant and associated generating assets will be transferred to APCo and KPCo on 1/1/2014. The cost of this investment will be recovered from APCo and KPCo customers as follows:

Appalachian Power Company – Generation - $69.1M (50%)
- $32.5M (47%) APCo VA base rate case filing, TYE 12/31/13, with cost projections through 1/31/16, effective 1/31/15; or through deferral of expenditures for recovery under the Environmental Rate Adjustment Clause (E-RAC) to be filed TBD, with cost projections through TBD.
- $29.7M (43%) APCo WV base rate case filing, TYE 12/31/14, with cost projections through 12/31/15, effective 2/1/16.
- $4.1M (6%) KgPCo purchased power pass-through from APCo under three-year settlement agreement phase-in of generation rates through 12/31/11 remains in effect post-2011 until new agreement is in place.
- $2.8M (4%) FERC Annual Formula Rate update, TYE 12/31/14, effective 6/1/15.

Kentucky Power Company – Generation - $69.1M (50%)
- $68.4M (99%) base rate case filing, TYE TBD, effective TBD.
- $0.7M (1%) FERC Annual Formula Rate update, TYE 12/31/14, effective 6/1/15.

Funding: **Included in IRC Presentation** Yes **Project Funded** Yes **Offset Source** N/A

Requested future year funds are included in the last official Forecast.

Approved By: D. Lee/P. Vegas/M. McCullough/ R. Powers/N. Akins **Approved On:** 2/7/2013

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	88,515,348	-	88,515,348
This Submission	49,684,234	-	49,684,234
Total	**$ 138,199,582**	**$ -**	**$ 138,199,582**

2013 Direct Cost Funding		Offset Source and Amount
In Forecast	$ 61,703,550	*N/A*
Offset	$ -	

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	VP, Fleet Operations	Lee, D.	See electronic approval attached	01/21/13
amt ≤ $ 10m	Opco President	Vegas, P.	See electronic approval attached	01/28/13
amt ≤ $ 20m	EVP-Generation	McCullough, M.		2/6/13
amt ≥ $ 20m	EVP & COO	Powers, B.		2/7/13
amt ≥ $ 20m	President & CEO	Akins, N.		2/7/13
CP&B Review	SVP, Corporate Planning & Budgeting	Dieck, L.		2/1/13

Project Contacts

Contact	Name	Telephone
Project Manager	Karl Adams	200-2084
Requisition Detail Provider	Jason Bryant	200-1482

Capital Improvement Approval Requisition

Reason for Revision Version 3

This revision (Phase 3) is required to authorize the completion of the engineering, procurement, construction, startup and commissioning to support a 3Q2014 in-service date.

Justification for Version 2

Version 2 completed Phase 2 engineering/design, ash silo erection, and procurement of all engineered equipment/materials.

Justification for Version 1

The re-issued National Pollutant Discharge Elimination System (NPDES) permit for the Mitchell Outfall -004 from the fly ash impoundment to Conners Run has been revised with lower selenium limits. Based on historical water quality testing, AEP will not be in compliance with the new selenium limits for this outfall through continued use of the current operating system/configuration. A preliminary engineering study has determined that by removing the Mitchell Plant's fly ash slurry contribution to the pond, the new NPDES selenium limits can be achieved at Outfall -004. Further analysis will be conducted to support this preliminary result.

AEP is required to be in compliance with the new NPDES limits beginning November 30, 2012. It is anticipated that following development of a detailed compliance strategy and schedule, an extension will likely be granted by the West Virginia Department of Environmental Protection to allow execution of the described plan.

Fly ash disposal for Mitchell will reach the fly ash (FA) pond design life capacity by July 2013 causing either: the need to physically increase or justify an increase to the existing capacity of the FA pond, unit curtailment or eventual shutdown of the units. Additionally, representatives from AEP and Consol Energy have joined as a Task Force to transition the operations, permits and future construction of the fly ash impoundment completely to Consol. This requires that AEP eliminate the wet disposal of fly ash from Mitchell Plant into the fly ash pond.

Studies were developed with the assistance of three OEMs to determine the options available to convert the Mitchell Units to dry fly ash handling. It was concluded that ash removal from the hoppers through installation of new vacuum pumps and a pressurized systems to blow ash to a new ash transfer facility comprised of 3 conventional ash silos is the preferred technology. The new ash transfer facility will be located on the east side of Route 2 and equipped to load ash into trucks only, for transport to the final disposal location. It is expected that this conversion process will be accomplished while both unit's remain on-line.

Funds will be used to:

- Secure contract for OEM services for ash handling system engineering, equipment procurement, and silo engineering/erection services.
- Secure alliance team for project execution that includes OEM, architectural engineer and general contracting services.
- Complete approximately 50% of the balance of plant engineering and design, including a detailed environmental and engineering assessment of anticipated selenium concentrations at Outfall -004.
- Secure required permits.
- Complete site preparation and installation of major equipment foundations.
- Definitive cost estimate for the project.

Capital Improvement Approval Requisition

Other Alternatives Considered

- Maintain wet sluicing system and install ash de-watering facility.
- Install bio-reactor to remove selenium and continue to raise FAP dam.
- Convert Kammer to dry ash handling or remove Kammer from service.
- Make no changes.

The following alternatives were considered to convert the ash handling system to dry:

- Utilize existing water powered hydroveyor exhausters as the vacuum source to pull ash from hoppers or install air-slides under each hopper for ash collection then blow ash to new ash transfer facility.

Alternative #1 requires a de-watering facility be installed near the current route of the existing Mitchell ash pipe to the FA pond to mechanically reduce the water content in the ash from approximately 95% to 20%. This alternative was evaluated as a closed loop system to eliminate discharge of contaminated transport sluice water, but would require holding tanks to be installed to contain the process water (est. 500,000 gal) in the event the system needed to be drained. It was not selected based on the uncertainty and risks associated with the water chemistry over time and constant presence of large amounts of process water that would require installation of a costly treatment facility.

Alternative #2 requires a large bio-reactor approximately 7 times the size that is currently being installed at Mountaineer. The bio-reactor would be capable of treating at least 6 million gallons daily (MGD) of water which represents only Mitchell's water contribution to the pond. Mitchell's 6MGD flow could not be treated prior to entering the pond due to the suspended solids; hence a treatment complex would need to be designed for at least a portion of the water on the outlet of the FA pond before it enters Conners Run. Additionally, the existing FA pond's water chemistry has not been analyzed to determine if harmful elements are present that would destroy the bio-reaction process. Based on the estimated cost of greater than $100M, feasibility of treating this volume of water, and uncertainty with the pond's chemistry, this option was not selected.

Alternative #3 is to maintain wet fly ash disposal at Mitchell and either convert the Kammer units to dry ash handling or remove Kammer from service. Based on Kammer's 2019 projected removal from service date, converting these units to dry was not evaluated. Mitchell is believed to be the largest contributor of selenium to the pond; greater than Kammer and Consol combined. Hence, elimination of Kammer's ash to the pond only, would have much less impact on the selenium concentrations at the outfall. Additionally, maintaining the wet ash transport/disposal process for Mitchell required for this alternative, does not support the anticipated forthcoming Coal Combustion Residuals (CCR) regulations.

Alternative #4 is to make no changes and will result in non-compliance with new NPDES selenium limits at the fly ash pond Outfall -004. Shutdown of the Mitchell units would be required for compliance with the new NPDES limits for this alternative to avoid a Notice of Violation.

Alternative #5A is predicated on the decision to convert Mitchell to a dry ash handling system and utilizes the existing water powered hyrdroveyors as the vacuum source to pull ash from hoppers. This technology was not selected since it offered no overall cost savings, continued to use large volumes of water in the ash handling system, and requires high auxiliary power consumption. This process is also not consistent with the ambition to minimize the use of water in the ash conveyance process.

Alternative #5B is also predicated on the decision to convert Mitchell to a dry ash handling system and requires that new fluidized conveyors be installed under each hopper for ash collection. The collected ash is then transferred to a series of pneumatic screw pumps and blown to the ash transfer facility. This option was not selected due to the lack of headroom under each hopper for air slide installation, the long unit outages required to complete the air-slide installation (10-16 weeks), significant reduction to hopper storage capacity, space constraints for screw pump installation, and no capital cost savings.

Capital Improvement Approval Requisition

Conclusion

The recommended solution is to convert both Mitchell fly ash handling systems to a dry process through the installation of a new vacuum/pressurized system and ash transfer facility located on the east side of Route 2. This solution should result in maintaining compliance with the revised NPDES selenium limits at the fly ash pond's Outfall - 004.

The total anticipated cost of this conversion is $138,199,581.

Associated/Future Project

Upon conversion of the Mitchell units to dry fly ash handling, a permanent storage location in the form of a nearby landfill will be required to dispose of the conditioned ash. In addition, a private truck haul road from the ash transfer facility to the landfill will also be required.

Date December 13, 2013

Company	CI/LI/CPP/Program Number	Version
AEP Gen Services KYPCo ~~Ohio Power~~	000023143 KMLFALFCI	3

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	DEA 12/13/13		DEA 12/13/13

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	D. Lee	12/1/2013	
	P. Vegas	12/2/2013	
	G. Pauley	12/13/2013	
1	D. Adams	DEA 12/13/13	
2	D. Lynch	12/16/13	
3	L. L. Dieck	LLD 12/17/13	
7	C. Zebula	CEZ 1/9/13	
	B. X. Tierney		
4	M.C. McCullough	MCM 11/19/13	
5	R. P. Powers	RPP 11/18/13	
6	N. K. Akins	NKA 12/26/13	
	Buckeye Power Approval		
7	Darryl Lynch - 28th floor Ext 1142		
		1-23-14	Approved in PeopleSoft
		Jan 2014	Month Included in Board Package

Alternate CP&B Contacts:
Darryl Lynch- 28th Floor - Ext 1142

Scanned File Name: ~~OPCo~~ KYPCo KMLFALFCI Version 3.pdf
GENCo 000023143

Capital Improvement Approval Requisition

Company: AEP Generation Resources, Kentucky Power Company **Version 3**

Project : KMLFALFCI & 000023143 - Mitchell Plant New Long Term CCR Landfill - Phase 3
Moundsville, WV

Description: New regulations regarding Selenium limits imposed on Conner Run outfall # 004 through our National Pollutant Discharge Elimination System (NPDES) permit are driving Mitchell Plant to convert to a dry fly ash handling system. The plan for disposal of the fly ash is trucking to a new landfill to be constructed at Gatts Ridge, adjacent to the existing site.

Version 1 (Phase 1) scope included the new landfill site selection, engineering and design, submittal of the permit applications required to begin landfill construction activities, and development of a cost estimate to complete construction of Phase 1 of the new landfill.

Version 2 (Phase 2) included construction of Cell 1 of 5 of the new landfill and stream mitigation activities required by the 401/404 permit. Phase 2 completion will coincide with completion of the ML DFA Project (000019836 – Mitchell Units 1&2 – DFA Conversion) and completion of the Landfill Haul Road (KMLFALFHR).

Reason for Revision: As described in Version 2, an incremental-funding request is necessary to fund Phase 3 of the landfill construction project. Cell 1 has one year of disposal capacity and was constructed to coincide and support the DFA completion for an ash disposal area. Phase 3 includes construction of Cell 2 of 5 of the landfill. Cell 2 will support disposal through approximately 2020 at which time a new Improvement Requisition will need to be generated to complete subsequent landfill construction. The total estimated cost for all 3 phases necessary to complete Cells 1 and 2 is $60.8M, a reduction of $4.0M from previous estimates. This reduction is due to transitioning from a conceptual estimate to a detailed estimate.

Authorization Amount:

Company/ Function	Previously Approved Amount	This Submission	Total Amount to be Authorized
AEP Generation Resources	19,987,430	10,409,181	30,396,611
Kentucky Power Company	19,987,430	10,409,181	30,396,611
Total	**$ 39,974,860**	**$ 20,818,361**	**$ 60,793,221**

Cash Flow:

	Prior Years	2014	2015	Future Years	Total
Capital	$ 30,721,828	$ 19,614,915	$ 9,689,353	$ 767,125	$ 60,793,221
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 30,721,828	$ 19,614,915	$ 9,689,353	$ 767,125	$ 60,793,221
Associated O&M	$ -	$ -	$ -	$ -	$ -

Start Date: 2/14/2011 **Completion Date:** 6/30/2016 **In Service Date:** 11/30/2015

Regulatory Cost Recovery:

AEP Generation Resources – Generation - $30.40M (50%)

- N/A

Kentucky Power Company – Generation - $30.40M (50%)

- $30.1M (99%) base rate case filing, TYE TBD, effective TBD.
- $0.3M (1%) FERC Annual Formula Rate update, TYE 12/31/15, effective 6/1/16

Funding: **Included in IRC Presentation** Yes **Project Funded** Yes **Offset Source** OPCO/KYPCO - G

Requested future year funds are included in the last official Forecast.

Approved By: D. Lee / C. Patton / G. Pauley / C. Zebula R. Powers / N Akins **Approved On:** 12/26/2013

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	39,974,860	-	39,974,860
This Submission	20,818,361	-	20,818,361
Total	**$ 60,793,221**	**$ -**	**$ 60,793,221**

2013 Direct Cost Funding		Offset Source and Amount
In Forecast	$ 23,847,320	*N/A*
Offset		

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	SVP, Business Unit	Lee, D.	See attached electronic approval	12/01/13
amt ≤ $ 10m	Opco Presidents	Vegas, P. Pauley, G.	See attached electronic approval	12/2/2013 12/13/13
amt ≤ $ 10m	EVP Gen Co	Zebula, C.		1/9/14
amt ≤ $ 10m	EVP Generation	McCullough, M.		
amt ≤ $ 20m	EVP & COO/EVP	Powers, R.		12/19/13
amt ≥ $ 20m	President & CEO	Akins, N.		12/20/13
CP&B Review	SVP CP&B	Dieck, L.		12/17/13

Project Contacts

Contact	Name	Telephone
Project Manager	Thomas Cooper	200-2039
Requisition Detail Provider	Jason Baker	200-2474

Capital Improvement Approval Requisition

Reason for Revision

An incremental funding request is necessary to complete the landfill construction project's Phase 3 CI scope. Cell 1 has one year of disposal capacity and was constructed to coincide and support the DFA completion for an ash disposal area. Phase 3 includes construction of Cell 2 of 5 of the landfill. Cell 2 will support disposal through approximately 2020 at which time a new Improvement Requisition will need to be generated to complete subsequent landfill construction. The total estimated cost for all 3 phases necessary to complete Cells 1 and 2 is $60.8M, a reduction of $4.0M from previous estimates.

Justification for Version 2

An incremental funding increase was necessary to complete the landfill project's Phase 2 CI scope. Phase 2 CI includes construction of Cell 1 of 5 of the new land fill and stream mitigation activities required by the 401/404 permit. Phase 2 CI completion will coincide with the completion of the ML DFA Project (000019836 – Mitchell Units 1&2 – Dry Fly Ash Conversion) and completion of the Landfill Haul Road (KMLFALFHR).

Justification for Version 1

Due to the proposed Mitchell Plant wet flyash system conversion to a dry system, a new solid waste disposal facility will need to be constructed and certified for the disposal of ash and other CCR by-products. Several available options were considered which required regulatory approval before we could pursue aggressively. As such, engineering and design of the more conventional options, Conner Run or Gatts Ridge must proceed in parallel. Second only to beneficial use, construction of a new local landfill is the most economically feasible disposal option.

Other Alternatives Considered

Several long term options have been considered. Listed below are those options along with the NPV of cost (in $Millions) with included disposal costs.

1) Construct / Upgrade Haul Road from Fish Creek Road to the Conner Run Impoundment (CRI) for beneficial Use. – **NPV $38.78**

2) Short conveyor to the Conner Run Impoundment (CRI) for Beneficial use. - **NPV $49.45**

3) Construct / Upgrade Haul Road from Fish Creek Road to the Conner Run Landfill (brownfield site) – **NPV $98.97**
4) Construct a short conveyor from the North Ash Transfer Facility to the Conner Run Landfill (brownfield site) – **NPV $109.64**

5) Construct / Upgrade Haul Road from Fish Creek Road to the Conner Run Landfill plus an additional length required to reach the Gatts Ridge Landfill site (greenfield). **NPV $114.19**

6) Do Nothing. Not pursuing beneficial use for the CCR's or the construction of a new landfill for CCR disposal will result in the ash having to be trucked to an offsite disposal location. Two options are available, trucking to Cardinal and trucking to a commercial landfill. The **NPV's respectively are $188.41 and $230.84**.

Capital Improvement Approval Requisition

Conclusion

Trucking CCR's to the new Gatts Ridge Landfill site for permanent disposal is the most economical option. Phase 1 included selection of the new landfill site, engineering and design, submittal of the permit applications required to begin landfill construction activities, and development of a cost estimate to complete construction of Phase 1 of the new landfill. Phase 2 includes engineering, material procurement, and construction of the leachate collection system, construction of Cell 1 of 5 of the new landfill, and stream mitigation activities required by the 401/404 permit. Phase 2 completion will coincide with the conversion to Dry Fly Ash (000019836 – Mitchell Units 1&2 – Dry Fly Ash Conversion) and completion of the Haul Road (KMLFALFHR). Phase 3 includes completion of Cell 2 of 5 which allows for deposition through year 2020.

Date March 1, 2013

Company	CI/LI/CPP/Program Number	Version
Ohio Power	KMLFALFHR	3

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	JLF 3-1-13		JLF 3-1-13

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
1	D. Lynch	3/5/13	
2	L. L. Dieck	3/6/13	
	B. X. Tierney		
	L. Hillebrand		
3	M. C. McCullough	3/12/13	
	D. E. Welch		
4	R. P. Powers	3/13/13	
	L. Barton		
	Buckeye Power Approval		
5	N. K. Akins	3/14/13	
6	Jenifer Fischer - 28th floor Ext 3032		
		3-14-13	Approved in PeopleSoft
		Mar 2013	Month Included in Board Package

Alternate CP&B Contacts:
Cathy Warchal - 28th Floor - Ext 1347

Scanned File Name: OPCo KMLFALFHR Version 3.pdf

Capital Improvement Approval Requisition

Company: Ohio Power Company **Version:** 3

Project : **KMLFALFHR Revision - Kammer - Mitchell New Landfill Haul Road - Phase 2B & 2C**
Moundsville, West Virginia

Description: New regulations regarding Selenium limits imposed on Conner Run outfall # 004 through our National Pollutant Discharge Elimination System (NPDES) permit are driving Mitchell Plant to convert to a dry fly ash handling system. The plan for disposal of the fly ash is trucking to a new landfill at Gatts Ridge, adjacent to the existing site. The current access road to the impoundment will not support continuous hauling on a permanent basis due to inadequate design and poor condition. Development of a new haul road will be required to facilitate ash transportation.

Phase 1 (Version 1) optimized the haul road route, initiated permitting activities, and further refined the cost estimate for project completion.

Phase 2A (Version 2) finalized the engineering, design, bidding and awarded of the Construction contract, and completed the rough-in of Section #2 of the Haul Road.

Reason for Revision: This funding request is necessary to fund the final phases (Phase 2B and 2C) of the New Haul Road project. Phase 2B includes construction of Section #1 of the Haul Road during the 2013 construction season. Phase 2C includes final paving of Section #2 and paving of the Landfill Access Road, to be completed during the 2014 construction season.

Authorization Amount:

Company/ Function	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$ 8,866,465	$ 15,067,852	$ 23,934,317

Cash Flow:

	Prior Years	2013	2014	Future Years	Total
Capital	$ 4,167,145	$ 10,814,460	$ 8,952,712	$ -	$ 23,934,317
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 4,167,145	$ 10,814,460	$ 8,952,712	$ -	$ 23,934,317
Associated O&M	$ -	$ -	$ -	$ -	$ -

Start Date: 2/14/2011 **Completion Date:** 12/31/2014 **In Service Date:** 6/30/2014

Continued on the next page

Capital Improvement Approval Requisition

Company: Ohio Power Company **Version:** 3

Project : **KMLFALFHR Revision - Kammer - Mitchell New Landfill Haul Road - Phase 2B & 2C**
Moundsville, West Virginia

Continuation from prior page

Regulatory Cost Recovery:

Ohio Power Company - Generation - $23.93M (100%)
Upon approval from State and Federal regulatory authorities, Ohio Power Company's generation fleet will transition to a competitive market. Equal shares of Mitchell Plant and associated generating assets will be transferred to APCo and KPCo on 1/1/2014. The cost of this investment will be recovered from APCo and KPCo customers as follows:

Appalachian Power Company - Generation – $11.97M (50%)

- $5.62M (47%) APCo VA base rate case filing, TYE 12/31/12, with cost projections through 1/31/15, effective 1/31/14; or through deferral of expenditures for recovery under the Environmental Rate Adjustment Clause (E-RAC) to be filed TBD, with cost projections through TBD.
- $5.15M (43%) APCo WV base rate case filing, TYE 12/31/14, with cost projections through 12/31/15, effective 2/1/16
- $0.72M (6%) KgPCo purchased power pass-through from APCo under three-year settlement agreement phase-in of generation rates through 12/31/11 remains in effect post-2011 until new agreement is in place.
- $0.48M (4%) FERC Annual Formula Rate update, TYE 12/31/14, effective 6/1/15.

Kentucky Power Company - Generation – $11.97M (50%)

- $11.85M (99%) base rate case filing, TYE TBD, effective TBD.
- $ 0.12M (1%) FERC Annual Formula Rate update, TYE 12/31/14, effective 6/1/15.

Funding:

Included in IRC Presentation	Yes	Project Funded	Yes	Offset Source	N/A

Requested future year funds are included in the last official Forecast.

Approved By: D. Lee/P. Vegas/M. McCullough/R. Powers/ N. Akins **Approved On:** 3/14/2013

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	$8,866,465	-	$8,866,465
This Submission	$15,067,852	-	$15,067,852
Total	**$ 23,934,317**	**$ -**	**$ 23,934,317**

2013 Direct Cost Funding		Offset Source and Amount
In Forecast	$ 9,084,200	*N/A*
Offset		

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	VP, Business Unit	Lee, D.	See electronic approval attached	2/21/2013
amt ≤ $ 10m	Opco President	Vegas, P.	See electronic approval attached	2/21/2013
amt ≤ $ 20m	EVP Generation	McCullough, M.		3/12/13
amt ≤ $ 20m	EVP & COO	Powers, R.		3/13/13
amt ≥ $ 20m	President & CEO	Akins, N.		3/14/
CP&B Review	Senior Vice President	Dieck, L.		3/6/13

Project Contacts

Contact	Name	Telephone
Project Manager	Thomas Cooper	200-2039
Requisition Detail Provider	Josh Gaudio	200-1042

Capital Improvement Approval Requisition

Reason for Revision

This incremental funding request is necessary to fund Phase 2B and 2C of the New Haul Road project. Phase 2B includes construction of Section #1 of the Haul Road during the 2013 construction season. Phase 2C includes final paving of Section #2 and paving of the Landfill Access Road, to be completed during the 2014 construction season.

Justification for Version 2

An incremental funding request was necessary to complete the Phase 2A engineering, design, permitting and the construction of Section #2 of the new haul road going from the Conner Run Impoundment to the Gatts Ridge Landfill site. This phase also finalized engineering and design on Section #1 of the haul road. Phase 2A completion supports construction activities associated with the Mitchell Plant new landfill project (KMLLFALFCI) set to begin first quarter 2013.

Justification for Version 1

New regulations regarding Selenium limits imposed on Conner Run outfall # 004 through our National Pollutant Discharge Elimination System (NPDES) permit are driving Mitchell Plant to convert to a dry fly ash handling system. The plan for disposal of the fly ash is trucking to a new landfill at Gatts Ridge, adjacent to the existing site. The current access road to the impoundment will not support continuous hauling on a permanent basis due to inadequate design and poor condition. Development of a new haul road will be required to facilitate ash transportation.

Phase 1 Haul Road E&D, in conjunction with the ML landfill project, identified the Gatts Ridge location as the new landfill site. Site surveying, surface and subsurface investigations, and roadway engineering and design have been completed to optimize the haul road location. The haul road route also takes into consideration potential environmental and cultural impacts identified in site evaluations.

Other Alternatives Considered

Several long term options have been considered. Listed below are those options along with the NPV of cost (in $Millions) with included disposal costs.

1) Construct / Upgrade Haul Road from Fish Creek Road to the Conner Run Impoundment (CRI) for beneficial Use. – **NPV $38.78**

2) Short conveyor to the Conner Run Impoundment (CRI) for Beneficial use. - **NPV $49.45**

3) Construct / Upgrade Haul Road from Fish Creek Road to the Conner Run Landfill (brownfield site) – **NPV $98.97**
4) Construct a short conveyor from the North Ash Transfer Facility to the Conner Run Landfill (brownfield site) – **NPV $109.64**

5) Construct / Upgrade Haul Road from Fish Creek Road to the Conner Run Landfill plus an additional length required to reach the Gatts Ridge Landfill site (greenfield). **NPV $114.19**

6) Do Nothing. Not pursuing beneficial use for the CCR's or the construction of a new landfill for CCR disposal will result in the ash having to be trucked to an offsite disposal location. Two options are available, trucking to Cardinal and trucking to a commercial landfill. The **NPV's respectively are $188.41 and $230.84**.

Capital Improvement Approval Requisition

Conclusion

Trucking Coal Cumbustion Residuals (CCR's) to the new Gatts Ridge Landfill site for permanent disposal is the most economical option. Phase 1 engineering and design located the optimum haul road route and refined the total project cost estimate. Phase 2 will be to complete engineering and construct the haul road. This CI will work in conjunction with the KMLFALFCI project.

Associated/Future Projects

Mitchell Dry Fly Ash Conversion Project – Project ID# 000019836/000019846
Kammer / Mitchell New Landfill Haul Road – Project ID# KMLLFALFCI

Additional Information

Phase 1 Haul Road E&D, in conjunction with the ML landfill project, identified the Gatts Ridge location as the new landfill site. Site surveying, surface and subsurface investigations, and roadway engineering and design have been completed to optimize the haul road location. The haul road route also takes into consideration potential environmental and cultural impacts identified in site evaluations.

Capital Program Approval Requisition
One Page Summary

Company:	Kentucky Power Company AEP Generation Resources Inc. **Version: 1**
Project:	MLU2ESP15 - Mitchell Unit 2 ESP Upgrade -
Location:	Moundsville, WV
Description:	Replace 32 high frequency T/R sets, replace existing automatic voltage controls, replace existing rapper PLC controls and install precipitator optimization system and associated communications.

Authorization Amount:

Company	Function	Previously Approved Amount	This Submission	Total Amount to Be Authorized
GENCO	GEN	$0	$1,930,167	$1,930,167
KYPCO	GEN	$0	$1,932,984	$1,932,984
	Total	**$0**	**$3,863,151**	**$3,863,151**

Cash Flow:

	Prior Years	2014	2015	Future Years	Total
Capital	$0	$1,927,322	$1,858,329	$0	$3,785,651
Removal	$0	$0	$77,500	$0	$77,500
Total To Be Authorized	**$0**	**$1,927,322**	**$1,935,829**	**$0**	**$3,863,151**
Less CIAC	$0	$0	$0	$0	$0
Net AEP Cash Flow	$0	$1,927,322	$1,935,829	$0	$3,863,151
Associated O&M	$0	$30,000	$142,500	$0	$172,500

Project Dates: **Start Date :** 04/01/2014 **In Service Date :** 06/30/2015 **Completion Date:** 06/30/2015

Regulatory Cost Recovery:

Kentucky Power Company - $1.93M (50%)
- $1.91M (99%) base rate case filing, TYE 9/30/14, effective 6/1/15 with forecasted Test Year.
- $0.02M (1%) FERC Annual Formula Rate update, TYE 12/31/15, effective 6/1/16.

AEP Generation Resources - $1.93M (50%)
- N/A.

Funding:	**Included in IRC Presentation :** Yes	**Project Funded :** Yes
Approved By : Daniel V Lee, Gregory G Pauley, Charles E Zebula		**Approved On :** 03/24/2014

Capital Program Approval Requisition

Funding and Approval

Direct Cost Funding:

	Prior Years	2014	2015	Future Years	Total
In Forecast $	$0	$1,641,962	$2,684,350	$0	$4,326,312
Offsets Required	$0	$0	-$1,038,675	$0	-$1,038,675
Total	**$0**	**$1,641,962**	**$1,645,675**	**$0**	**$3,287,637**

Required Signatures:

Status	Name	Date
Approved	Teresa M Jeffers	03/07/2014
Approved	Michael L Belter	03/07/2014
Approved	Timothy V Riordan	03/07/2014
Approved	Aaron M Sink	03/10/2014
Approved	Toby L Thomas	03/10/2014
Approved	Robert L Walton	03/10/2014
Approved	John M McManus	03/10/2014
Bypassed	Christian T Beam	03/12/2014
Approved	Brian K Rupp	03/12/2014
Approved	Ranie K Wohnhas	03/12/2014
Approved	Daniel V Lee	03/13/2014
Approved	Gregory G Pauley	03/17/2014
Approved	Franz D Messner	03/17/2014
Approved	Charles E Zebula	03/18/2014
Approved	Jenifer L Fischer	03/24/2014

Project Contacts:

Type	Name
Detail Provider	ELLIOTT,WILEY J
Project Manager	ELLIOTT,WILEY J

Capital Program Approval Requisition

Component CI's

Component ID	Company	Description of Work	Previously Approved ($)		This Submission ($)		Total Authorized ($)		
			Capital	Removal	Capital	Removal	Capital	Removal	Total
000023130	GENCO	ML U2 ESP Upgrades	0	0	1,930,167	0	1,930,167	0	1,930,167
		GENCO Total :	**0**	**0**	**1,930,167**	**0**	**1,930,167**	**0**	**1,930,167**
000021259	KYPCO	ML U2 ESP Upgrades	0	0	1,855,484	77,500	1,855,484	77,500	1,932,984
		KYPCO Total :	**0**	**0**	**1,855,484**	**77,500**	**1,855,484**	**77,500**	**1,932,984**
		Grand Total :	**0**	**0**	**3,785,651**	**77,500**	**3,785,651**	**77,500**	**3,863,151**

Capital Program Approval Requisition

Additional Information

Project Justification:	Minimize or eliminate opacity related curtailments and outages.
Other Alternatives Considered:	Do nothing and delay installation.
Conclusion:	Replace 32 high frequency T/R sets, replace existing automatic voltage controls, replace existing rapper PLC controls and install precipitator optimization system and associated communications.

PROJECT APPROVAL REQUISITION

Company: AEP Generating **Funding Project Number:** RKAEG0418

Authorization Type: X Capital Improvement ___ Lease Improvement

___ Original Version: 00
X Revision Number: 1

Business Line: Generation

Location: Rockport Generating Plant Unit No. 2 – I&M/AEG: 0115

Project Title: Rockport Plant Unit 2 Girder Blower Replacement

Brief Description: The CI is being revised to complete installation for supplying electrically heated seal air to the precipitator girder boxes. New girder blowers were installed in 2004. An unheated seal air supply, as well as insufficient blower flow and pressure have resulted in corrosion of ESP internal structural steel and fly ash deposition in the girder box. This has also lead to roof corrosion in the precipitator; support brackets and other pieces of metal failing and falling into the ESP where they ground the bus section or plug the fly ash hopper. Furthermore, flyash contaminants have resulted in tracking and arcing which in turn cracks insulators. To eliminate this problem, heated air is needed.

Project Dates:	Start:	Completion:	Authorization Needed by:
	8/1/2004	9/1/2007	6/15/2005

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$497,000	$0	$497,000
This Submission	$523,265	$0	$523,265
Total ($)	**$1,020,265**	**$0**	**$1,020,265**

Note: Amount to be authorized is the total amount

Note: The costs above represent 50% of the total. There are two CI's that cover this project.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W. L.		6/16/05
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R. P.		
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $ 50m	Board of Directors	Keane, J.	Secretary	
CP&B Review	Senior VP	Munczinski, R		6/27/05

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by

Project Management Review Group? x Yes ___ No
Nuclear Project Review Group? ___ Yes ___ No

Comments: PMRG 3/8/05 agreed with need but disagreed with high cost of steam heat. Project was changed to electric heat to lower cost.

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2004	2005	2006	2007	2008	Future Years	Total ($)
Capital	$497,965	$127,300	$0	$395,000			$1,020,265
Removal							
Amount to be Authorized	$497,965	$127,300	$0	$395,000			$1,020,265
Assoc. O & M							

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

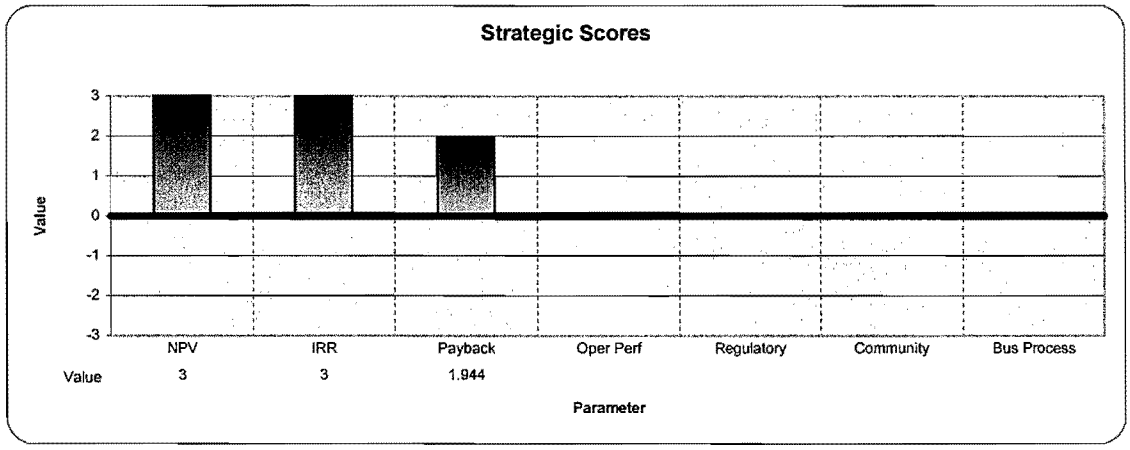
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	**27%**	**$1,488**	**6.1**	**7.9%**

Note: These results must match all background information

Scoring Summary

X **Discretionary** ___ **Mandated**



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			
	Rare/Remote		T, F	S

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

The above financial analysis is from the original CI. A revised financial analysis was not performed.

PROJECT APPROVAL REQUISITION

Revision 1

Project Justification

- This is a revision to an original CIA with a portion of the work completed in 2004. New lower speed girder blowers have been installed and are in operation using ambient air. The new girder blowers have solved the reliability issue with the original blowers. However, installation of steam and condensate piping to provide heated seal air has not been completed in order to stay within approved CI funds. This revision is to complete the installation of heat into the girder boxes.

- The original CI budget was based on estimates from labor contractors prior to an adequate workscope/design being completed. The extent of the work was underestimated. Better pricing was received prior to start of work using actual design drawings. A reduced workscope was completed to install the new blowers but not the steam and condensate piping due to the higher estimate..

- Design basis is confirmed by good experience at Mountaineer Plant heating the air with a limited amount of electric heat at each insulator (total of 1024 heaters at 1 kW each). Mountaineer Plant has proven that the extra BTU's available with steam are not required. As a result the steam heat option will not be pursued further.

Conclusion

- Install electric heaters into the ductwork downstream of each purge air blower. A total of 1 MW of aux power will be used. The heated purge air will prevent corrosion of the precipitator roof and better protect ceramic support insulations.

Other Alternatives Considered

- Install eight new blowers and electric heaters on each insulator (total of 1024 heaters at 1 kW each). This option is an additional $210,000 in capital and is considered higher maintenance.

- Install steam heat to a steam coil located at each blower. This option required a long steam and condensate piping system. The total additional capital cost was $255,000.

Associated Projects

- 50% of this project will be capitalized under RKIMC0418
- Unit 1 Girder Blowers and heat will be replaced in the years 2005 and 2007.

Revision 0

Project Justification & Explanation of Scores

- Rockport Unit 2 uses electrostatic precipitators for pollution control. In electrostatic precipitation, suspended particles in the flue gas are electrically charged, then attracted to collecting plates. The source of voltage travels through a discharge electrode frame which is suspended from ceramic insulators. These insulators are supported off of the floor of the precipitator girder boxes. (The underside of this floor is known as the precipitator roof.) An unheated, poor volume air supply results fly ash accumulation and water vapor condensation on the insulators. This leads to electrical tracking and failure of the insulator, which will ground a bus section and remove it from service.

- An unheated seal air supply results in cool air entering the girder box, flowing through the insulators, where it mixes with the flue gas stream. At this location the flue gas temperature drops below its SO_3

PROJECT APPROVAL REQUISITION

dewpoint and sulfuric acid condenses on to and fails the steel in this area. The greater the sulfur concentration in the coal the lower the dewpoint temperature. This has manifested itself as observed roof corrosion in the precipitator, support brackets and other pieces of metal. When the metal fails and falls into the ESP they can ground the bus section or plug the fly ash hopper; both of which will eventually remove the bus section from service and collection efficiency is reduced. Ultimately, an entire wire or plate frame could fail and fall into the ESP. To eliminate this problem, a new, adequately designed, heated air supply is needed.

- If corrosion is allowed to continue, failures of insulator supports will occur more frequently. Repairs will need to be performed yearly to keep up with the corrosion. Even with good maintenance it is predicted that a 5 day outage will result.

Conclusion

- Install a steam heated purge air system with two 100% flow requirement blowers. The installation will include new insulated ductwork and tie into the existing girder boxes. The heated purge air will prevent corrosion of the precipitator roof and better protect ceramic support insulations.

Other Alternatives Considered

- Utilize warm secondary air from Unit 2. Extra capacity of the FD fans allows this to be a viable option. Unfortunately the air quality is poor and this air needs to be filtered to a high quality. This alternative was determined to be unacceptable due to increased maintenance costs and unsatisfactory results when installed elsewhere on the fleet.

- Install individual blowers and electric heaters at each girder box. 6 MW of electricity would be required to heat the air. Electrical heaters are higher cost than low energy plant heating steam. This alternative was unacceptable due to high operating cost.

Background Information

- The original design purge air system utilized sixteen blowers mounted on top of the precipitators. Air from these blowers traveled through openings in the top of the electrode support insulators. This air keeps flyash from collecting in the girder box since it operates at a higher pressure than the precipitator. Individual electric heaters (1 MW total) were wrapped around the insulators as an attempt to prevent moisture from collecting on the insulators that could then result in an electrical short.

- The individual electric heaters have been unreliable. The heater supplier has not been able to keep these heaters working. The temperatures experienced in the girder box are beyond the design ability of these heaters.

- The original blowers were of inadequate design for the flow required. The blowers are running at a speed higher than good engineering practice allows. Thus, these blowers have also been unreliable. Currently 8 of the 16 blowers remain in operation, as spare parts are unavailable for repair. As a result the flow to the insulators is lower than recommended.

PROJECT APPROVAL REQUISITION

Project Contacts

Contact	Name	Telephone
Project Manager	Steve Pfeister	8 – 282 - 2216
Requisition Detail Provider	Jeff Hofacre	8 – 200 - 3295

PROJECT APPROVAL REQUISITION

Company: Indiana Michigan Power **Funding Project Number:** RKIMC0418

Authorization Type: X Capital Improvement ___ Original Version: 00
___ Lease Improvement X Revision Number: 1

Business Line: Generation

Location: Rockport Generating Plant Unit No. 2 – I&M/AEG: 0115

Project Title: Rockport Plant Unit 2 Girder Blower Replacement

Brief Description: The CI is being revised to complete installation for supplying electrically heated seal air to the precipitator girder boxes. New girder blowers were installed in 2004. An unheated seal air supply, as well as insufficient blower flow and pressure have resulted in corrosion of ESP internal structural steel and fly ash deposition in the girder box. This has also lead to roof corrosion in the precipitator; support brackets and other pieces of metal failing and falling into the ESP where they ground the bus section or plug the fly ash hopper. Furthermore, flyash contaminants have resulted in tracking and arcing which in turn cracks insulators. To eliminate this problem, heated air is needed.

Project Dates:	Start:	Completion:	Authorization Needed by:
	8/1/2004	9/1/2007	6/15/2005

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$497,000	$0	$497,000
This Submission	$542,548	$0	$542,548
Total ($)	**$1,039,548**	**$0**	**$1,039,548**

Note: Amount to be authorized is the total amount

Note: The costs above represent 50% of the total. There are two CI's that cover this project.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W. L.		6/14/05
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R. P.		
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $ 50m	Board of Directors	Keane, J.	Secretary	
CP&B Review	Senior VP	Munczinski, R		6/24/05

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by

Project Management Review Group? x Yes ___ No
Nuclear Project Review Group? ___ Yes ___ No

Comments: PMRG 3/8/05 agreed with need but disagreed with high cost of steam heat. Project was changed to electric heat to lower cost.

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2004	2005	2006	2007	2008	Future Years	Total ($)
Capital	$517,248	$127,300	$0	$395,000			$1,039,548
Removal							
Amount to be Authorized	$517,248	$127,300	$0	$395,000			$1,039,548
Assoc. O & M							

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

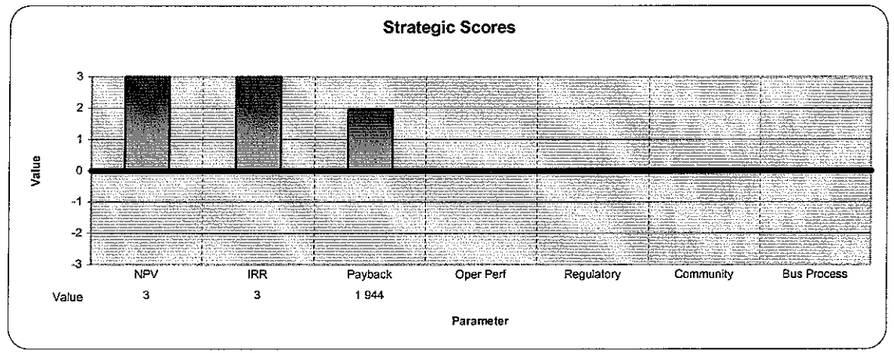
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	27%	$1,488	6.1	7.9%

Note: These results must match all background information

Scoring Summary

X Discretionary ___ Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			
	Rare/Remote		T, F	S

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

The above financial analysis is from the original CI. A revised financial analysis was not performed.

PROJECT APPROVAL REQUISITION

Revision 1

Project Justification

- This is a revision to an original CIA with a portion of the work completed in 2004. New lower speed girder blowers have been installed and are in operation using ambient air. The new girder blowers have solved the reliability issue with the original blowers. However, installation of steam and condensate piping to provide heated seal air has not been completed in order to stay within approved CI funds. This revision is to complete the installation of heat into the girder boxes.

- The original CI budget was based on estimates from labor contractors prior to an adequate workscope/design being completed. The extent of the work was underestimated. Better pricing was received prior to start of work using actual design drawings. A reduced workscope was completed to install the new blowers but not the steam and condensate piping due to the higher labor estimate.

- Design basis is confirmed by good experience at Mountaineer Plant heating the air with a limited amount of electric heat at each insulator (total of 1024 heaters at 1 kW each). Mountaineer Plant has proven that the extra BTU's available with steam are not required. As a result the steam heat option will not be pursued further.

Conclusion

- Install electric heaters into the ductwork downstream of each purge air blower. A total of 1 MW of aux power will be used. The heated purge air will prevent corrosion of the precipitator roof and better protect ceramic support insulations.

Other Alternatives Considered

- Install eight new blowers and electric heaters on each insulator (total of 1024 heaters at 1 kW each). This option is an additional $210,000 in capital and is considered higher maintenance.

- Install steam heat to a steam coil located at each blower. This option required a long steam and condensate piping system. The total additional capital cost was $255,000.

Associated Projects

- 50% of this project will be capitalized under RKAEG0418
- Unit 1 Girder Blowers and heat will be replaced in the years 2005 and 2007.

Revision 0

Project Justification & Explanation of Scores

- Rockport Unit 2 uses electrostatic precipitators for pollution control. In electrostatic precipitation, suspended particles in the flue gas are electrically charged, then attracted to collecting plates. The source of voltage travels through a discharge electrode frame which is suspended from ceramic insulators. These insulators are supported off of the floor of the precipitator girder boxes. (The underside of this floor is known as the precipitator roof.) An unheated, poor volume air supply results fly ash accumulation and water vapor condensation on the insulators. This leads to electrical tracking and failure of the insulator, which will ground a bus section and remove it from service.

- An unheated seal air supply results in cool air entering the girder box, flowing through the insulators, where it mixes with the flue gas stream. At this location the flue gas temperature drops below its SO_3

dewpoint and sulfuric acid condenses on to and fails the steel in this area. The greater the sulfur concentration in the coal the lower the dewpoint temperature. This has manifested itself as observed roof corrosion in the precipitator, support brackets and other pieces of metal. When the metal fails and falls into the ESP they can ground the bus section or plug the fly ash hopper; both of which will eventually remove the bus section from service and collection efficiency is reduced. Ultimately, an entire wire or plate frame could fail and fall into the ESP. To eliminate this problem, a new, adequately designed, heated air supply is needed.

- If corrosion is allowed to continue, failures of insulator supports will occur more frequently. Repairs will need to be performed yearly to keep up with the corrosion. Even with good maintenance it is predicted that a 5 day outage will result.

Conclusion

- Install a steam heated purge air system with two 100% flow requirement blowers. The installation will include new insulated ductwork and tie into the existing girder boxes. The heated purge air will prevent corrosion of the precipitator roof and better protect ceramic support insulations.

Other Alternatives Considered

- Utilize warm secondary air from Unit 2. Extra capacity of the FD fans allows this to be a viable option. Unfortunately the air quality is poor and this air needs to be filtered to a high quality. This alternative was determined to be unacceptable due to increased maintenance costs and unsatisfactory results when installed elsewhere on the fleet.

- Install individual blowers and electric heaters at each girder box. 6 MW of electricity would be required to heat the air. Electrical heaters are higher cost than low energy plant heating steam. This alternative was unacceptable due to high operating cost.

Background Information

- The original design purge air system utilized sixteen blowers mounted on top of the precipitators. Air from these blowers traveled through openings in the top of the electrode support insulators. This air keeps flyash from collecting in the girder box since it operates at a higher pressure than the precipitator. Individual electric heaters (1 MW total) were wrapped around the insulators as an attempt to prevent moisture from collecting on the insulators that could then result in an electrical short.

- The individual electric heaters have been unreliable. The heater supplier has not been able to keep these heaters working. The temperatures experienced in the girder box are beyond the design ability of these heaters.

- The original blowers were of inadequate design for the flow required. The blowers are running at a speed higher than good engineering practice allows. Thus, these blowers have also been unreliable. Currently 8 of the 16 blowers remain in operation, as spare parts are unavailable for repair. As a result the flow to the insulators is lower than recommended.

PROJECT APPROVAL REQUISITION

Project Contacts

Contact	Name	Telephone
Project Manager	Steve Pfeister	8 – 282 - 2216
Requisition Detail Provider	Jeff Hofacre	8 – 200 - 3295

L

Date January 25, 2007

Company	CI/LI/CPP/Program Number	Version
AEP System	HGMONITOR	2

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PC 1-25-2007		PC 1-25-2007

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Torpey		Component CI #s 000013367, 000013368, 000014655, 000014540, 000014541, 000013322, 000014542, 000013369, 000014662, 000014663
2	R. E. Munczinski	for Rom 11/25/07	
	S. Smith		
	H. Koeppel		
	J. Hamrock		
	S. Tomasky		
	M. K. Nazar		
3	S. N. Smith	See Attached for Electronic Approval Signature	
4	N. K. Akins	See Attached for Electronic Approval Signature	
	B. Bond (SWEPCO T&D)		
	T. M. Hagan		
	R. P. Powers		
	M. Heyeck		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
5	M. G. Morris	1-28-07	
6	Paula Cahill - 28th floor Ext 2494		
		1-29-2007	Approved in PeopleSoft
		2-07	Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Pat Bachman - 28th Floor - Ext 2888

AEP Printing Services:

Scanned File Name: AEP System HGMONITOR Version 2.pdf

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PROGRAM APPROVAL REQUISITION

Company: AEP System **Program Number:** HGMONITOR

Authorization Type: X Capital Program Version Number: 02

Business Line: Generation

Location: All Fossil Plants – 7 Operating Companies

Project Title: Mercury Compliance Monitoring Program – Phase 2

Brief Description: Phase 2 is the implementation phase of the Mercury Compliance Monitoring Program. During Phase 2, a complete Continuous Monitoring System, based on the design basis developed in Phase 1, will be installed on every stack in the AEP Fossil-Fuel Fleet. This Program CI revision requests the balance of funds to design, install, commission, and certify these systems by the deadline of 1/1/09. These tasks will be accomplished based on the design basis scope developed through research and evaluation of technology in phase 1.

Regulatory Cost Recovery:

AEP Ohio - RSP plan is in place, which provides for cost recovery associated with new environmental regulations on an annual basis 2007 mercury monitoring costs in Ohio included in filing made 1/23/2007. If approved, cost recovery will begin in May, 2007
APCO - Environmental & Reliability Rider is an annual filing in Virginia West Virginia allocated portion recoverable in next base rate case, est. 2010
I&M - Possible Indiana test year 2006-2007 timeframe, for potential future filing late 2007. No cases currently scheduled for Michigan
Kentucky Power - An Environmental Surcharge is in place, which can be filed annually to recover costs
AEP Texas - Generation function is deregulated in Texas-ERCOT No opportunity for regulatory cost recovery.
PSO - Formula rates are being proposed by PSO in the current filing before the OCC. If approved, rates could be regularly adjusted for changes in rate base, if warranted.
SWEPCo - The Arkansas and Texas Jurisdictions anticipate test years ending June 2008. These cases will be driven by the peaking units being installed. In Louisiana, Formula Rates are being proposed by SWEPCO, which would allow for annual adjustments to rates for changes in rate base, if warranted

Project Dates:	Start:	Completion:	In-Service:
	05/01/06	12/31/09	04/30/2009

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$2,269,472	$0	$2,269,472
This Submission	$42,246,003	$0	$42,246,003
Total ($)	$44,515,475	$0	$44,515,475

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP	Sigmon, W.	See Attached	
$ 10m ≤ amt < $20m	Executive Vice President/COO	Akins, N	See Attached	
$20m ≤ amt < $50m	Chairman President & CEO	Morris, M		1.28.07
amt ≥ $ 50m (if not in budget)	Board of Directors	Keane, J.		

PROGRAM APPROVAL REQUISITION

CP&B Review Senior VP 1/25/07

Budget Availability for this Authorization: x In Budget ___ Offset

Offset (source & amount):

Project Expenditure Schedule

Year	Prior Years	2006	2007	2008	2009	Future Years	Total ($)
Capital		$1,241,361	$15,814,324	$27,104,800	$354,990		$44,515,475
Removal		$0	$0	$0	$0		
Amount to be Authorized		$1,241,361	$15,814,324	$27,104,800	$354,990		$44,515,475
Assoc. O & M							

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent

Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	**N/A**	**N/A**	**N/A**	**N/A**

Note: These results must match all background information

Discretionary/Mandated

___ **Discretionary** x **Mandated**

PROGRAM APPROVAL REQUISITION

Program CIs

CI Number	Operating Company	Estimated In Service Date	Previously Approved Amount ($)	This Submission ($)	Total Cost ($)
000013367	Appalachian Power Company- Generation	02/28/09	45,530	14,273,107	14,318,637
000013368	Indiana Michigan Power Company- Generation	10/31/08	22,767	3,593,656	3,616,423
000014655	AEP Generating Co – Generation	10/31/08	0	789,073	789,073
000014540	Kentucky Power Company- Generation	05/31/07	0	1,247,474	1,247,474
000014541	Ohio Power Company- Generation	10/31/08	0	8,828,700	8,828,700
000013322	Columbus Southern Power Company- Generation	04/30/09	2,178,586	3,883,688	6,062,274
000014542	Southwestern Electric Power Company- Generation	10/31/08	0	6,932,961	6,932,961
000013369	Public Service Company of Oklahoma- Generation	04/30/08	22,589	1,847,367	1,869,956
000014662	AEP Texas North Company – Generation	01/31/08	0	743,765	743,765
000014663	AEP Texas Central Company – Generation	01/31/08	0	0	106,212
Total Cost ($)			**2,269,472**	**42,246,003**	**44,515,475**

Project Justification & Explanation of Scores

As part of The Clean Air Mercury Rule (70FR 28606) publicized on May 18, 2005, subsequent Fossil Fuel Electric Power Plants are required to begin monitoring mercury emissions in Flue Gas beginning January 1, 2009 All fossil plants within the Fleet are affected by this mandate.

This second phase (Implementation Phase) will be funded to perform all necessary engineering, design, scheduling, environmental planning, permitting, and construction of the mercury monitoring systems at all remaining facilities. The single technology and vendor proven in the first phase as the most reliable, cost effective, and accurate will be selected for a single implementation at all remaining facilities.

Scope

The goal for Phase 2 is to successfully implement the proven technology equipment at all applicable fossil-fuel plants by 1/1/09. This includes the establishment of an annual certification plan and resources for the fleet to meet RATA specifications. The objectives to meet these goals are as follows:

- A developed project plan and strategy with Engineering Services and Vendors which refined the program scope, cost, and schedule, and was routed for organizational approval.
- Coordination around the planned outages for Continuous Mercury Monitoring Systems (CMMS) installations to steer clear of contractor resource loading and stack accessibility issues. The complete CMMS installation can be performed with the unit running, therefore does NOT require an outage.
- Coordinate the Engineering and Design tasks with the sequenced installations based on the construction planning. Supplement with Contractors if necessary.
- Develop Phase 2 work packages with Engineering Services and Vendors.
- Execute the work at each site with the AEP RSO Organization, Installation Contractors, or releases against existing ARA Contracts.
- Develop a certification program for the fleet to include teams, plans, and budgets to meet annual RATA criteria for all installation sites

Program Summary:

PROGRAM APPROVAL REQUISITION

- As part of The Clean Air Mercury Rule (CAMR), coal-fired electric generating stations are required to monitor mercury emissions in the flue gas. All operating coal-burning plants within the AEP fleet are affected by this mandate.
  - Certification testing begins 1/1/08
  - Installation and Certification must be complete by 1/1/09
  - Emission Allowance Surrender begins 1/1/10
- Due to the relatively immature state of the technology available to accurately and reliably monitor mercury emissions, this regulatory mandated project will be split into two (2) project phases; a design-basis evaluation phase (Phase 1), and a fleet-wide implementation phase (Phase 2)
- Phase 1 is to engineer, design, and install two Continuous Mercury Monitoring Systems (CMMS) utilizing differing technologies. Once installed and operating, the project team will evaluate the systems on total evaluated cost basis.
- Phase 2 will utilize the data from Phase 1, to proceed with CMMS implementation. Phase 2 requires all systems to be certified by 1/1/09.

Additional Notes:

- This is a required environmental compliance project. Therefore a financial cost/benefit analysis is not required
- The lessons-learned with technology, cost, construction, and scheduling during phase 1 was an extreme benefit to the program and was the basis for the design, estimate, and schedule strategy in the planning of phase 2.
- There are funds budgeted in 2007 through 2009 to support Phase 2 portion of the program.
- The Program Scope and Estimate is based on the following principles:
  - Internal Labor shall be utilized for engineering and design
  - O&M funds are budgeted to provide the required one full-time-equivalent resource per stack at each plant.
  - Training classes on the specialty equipment will be held, and all applicable plant personnel must sign up to attend
  - Platform work is necessary at certain sites to accommodate the new equipment in the stack.
  - The design basis from phase 1 features 70% repeatability throughout the fleet, which reduces engineering and design cost.
  - A five percent (5%) escalation factor is included for material and labor increases from 2007 to 2008
  - The only accepted RATA method is budgeted in the project to pay for only the initial certifications, with the respective plant O&M budgets to assume all subsequent annual tests. This cost can be reduced by the EPA accepting alternative methods

Conclusion:

Execution of this Mercury Compliance Monitoring Program is recommended:

- All coal burning plants will need a Mercury Compliance Monitoring in place by 1/1/09 as mandated by the CAMR

Additional Information

Other Alternatives Considered

- No alternatives to monitoring exist.

Background Information

There are commercially available (but not completely proven) Continuous Mercury Monitoring Systems (CMMS) and Semi-Continuous Mercury Monitoring Systems (SCMMS) for flue gas mercury. The CMMS and SCMMS function similar in principle currently installed Continuous Emissions Monitoring Systems (CEMS). However, the technology is still being improved and requires a much higher level of maintenance. Both CMMS and SCMMS feature five key components; extraction probe, sample pretreatment/conversion system, sample transport, mercury analyzer, and calibration system

Extraction Probe

PROGRAM APPROVAL REQUISITION

This is used to extract a representative sample of flue gas from the stack Current designs use a silicon-coated inertial separation filter to separate the fly-ash from the bulk gas sample.

Pretreatment/Conversion Components

These components can be located in either the probe or at the sample location This system converts all of the mercury to elemental mercury (which is the only species the monitors can analyze) and removes gases that interfere with the analysis process Wet chemical converters have been used for this system, but have proven to be very operator intensive and not desirable These are not currently being evaluated for continuous operation at AEP Currently, dry chemical systems are being developed utilizing thermal catalyst designs.

Sample Transport

This transports the sample gas from the stack sampling area to the analyzer location (heated tubing bundle). The sample lines must be kept at an elevated temperature (>380°F) to insure that mercury does not deposit in the sample transport lines. The transport line is made of semiconductor-grade, conditioned Teflon (PFA)

Mercury Analyzer

The mercury analyzers under consideration use either cold-vapor atomic fluorescence or cold vapor atomic absorption spectroscopy (CVAF or CVAA) The CVAF method induces mercury atoms to fluoresce, like a fluorescent light and then measures the fluorescence level to calculate mercury concentration. The CVAA method calculates mercury concentration by comparing the energy emitted to the energy received. According to a press release 12/6/05, the CVAF method improves the sensitivity compared to the CVAA method by 50 to 100 %. CVAF appears to be the preferred method to achieve EPA compliance

Calibration System

This system is an automated system which introduces a zero gas and known span gas directly into the analyzer The analyzers must be calibrated using elemental and oxidized mercury, pursuant to the rule. Elemental mercury can be either in cylinder form or created using a calibration gas generator (currently preferred method). Oxidized mercury can only be created using a gas generator. At the present time, elemental and oxidized mercury calibration gas standards and protocols are not fully developed by EPA/NIST.

TECHNICAL ISSUES, RISKS, & OBSTACLES

The following Issues, Risks, and Obstacles are identified and can affect the cost, schedule, and success of the program Efforts have been made in the phased program approach to address each issue

- Program Implementation
  - Fleet operations approve the work activities, and the operational impacts on the Units.
  - Internal and external resources required to support the program will be available.
  - Plant O&M Resources (i e. one FTE per stack) will be available for system maintenance once online
  - Technical Resources will be available for certification, and annual RATA's.
  - The outage plans for the Western Fleet are unknown for 2007 and 2008 at this time.
  - As of 12/1/06, the project team has frozen the list of sites to be included in this program Any retirements or unit activities that would affect the list is considered a scope change, and would constitute a CI revision.
  - Currently there are no provisions for incorporation or monitoring of stratification issues pertaining to the CMMS installations The current rule does not define the criteria for this phenomenon, and therefore is not budgeted in this program scope.
- Mercury Monitoring Equipment
  - It has been determined in Phase 1 that installed redundancy is unnecessary for this program. The backup plan is to have a sorbent trap system supplied per system to stay in compliance in the event of CMMS unavailability.
  - National Institute of Standards and Technology (NIST) standards and EPA protocols for certification of the oxidized and elemental mercury gas standards have yet to be

PROGRAM APPROVAL REQUISITION

developed. This poses an uncertainty as to the scope and cost of initial certification, and ongoing maintenance requirements.
  - It has been determined in Phase 1 that the long transport lines do not pose a problem with the reliability or accuracy of the systems. Therefore the design basis features the analysis equipment at the base of the stack
  - The potential inability of the Vendor's to provide equipment to support the Program schedules in accordance with EPA deadlines is a significant concern. Steps are being planned to accommodate the increased demand on this type of equipment from a limited number of vendors
- RATA Methodology
  - The current accepted RATA (Ontario-Hydro, OH) method is extremely difficult to implement. On wet scrubbed units or stratified gas streams, samples must be extracted from three points with one being the center of the stack. This will pose as a challenge on the larger stacks.
  - OH Method requires a long lag time to analyze all the samples. Approximately 150-170 individual analysis must be conducted. Sample collection and analysis can take at least 2 weeks to compile. OH Method has a high degree of uncertainty.
  - Environmental Services is still working with EPRI to gain EPA approval to utilize Sorbent Traps as an acceptable RATA method. This could potentially save AEP approximately $2 million in annual testing costs. Since the current scope is based on the current rule, a change in the method will require a scope change and possible CI revision.
  - Despite the fact that NIST standards and EPA protocols have yet to be developed and there are other issues as enumerated above, the plan presented herein is the best alternative for us to follow and meet the requirements to have mercury monitoring equipment in place by the 01/01/09 deadline. We will continue to stay abreast of external developments related to the monitoring equipment and standards.

Associated / Future Projects

- A separate Phase 2 CI will be routed for the Buckeye Power Co. portion of Cardinal Plant during the first quarter of 2007.
- The OVEC/IKEC portion of the program will be separately funded during the second quarter of 2007.

Project Contacts

Contact	Name	Telephone
Project Manager	James A. Rappach	200-1464
Project Engineer	Philip A. Sawich	200-2587
Environmental Services	Manojit Sukul	200-1227

Date June 11, 2007

Company	CI/LI/CPP/Program Number	Version
Indiana Michigan Power	RK002ACI0	2

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PC 6-11-2007		PC 6/1-2007

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Martin		Related AEG Joint Plant CI#RK002ACIA
2	R. E. Munczinski		6/12/07
	S. Smith		
	H. Koeppel		
	J. Hamrock		
	S. Tomasky		
	M. K. Nazar		
	S. N. Smith		
	N. K. Akins		
	B. Bond (SWEPCO T&D)		
	T. M. Hagan		
	R. P. Powers		
	M. Heyeck		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
	M. G. Morris		
3	Paula Cahill - 28th floor Ext 2494		
		6-13-2007	Approved in PeopleSoft
			Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Pat Bachman - 28th Floor - Ext 2888

AEP Printing Services:

Scanned File Name: Indiana Michigan Power RK002ACI0 Version 2.pdf

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Generation CI/LI Approval Routing Document

Status: Approved

Last populated: 05/29/2007 03:49 PM

Plant	Unit	Funding Project #	Ver. #	Project Type
Rockport	2	RK002ACI0	2	Project
		RK002ACIA	2	

Project Title: RK U2 Carbon Injection

Outage Code: (if necessary)

In-service date: 6/1/2007

Brief Description of Project (sufficient to determine that the project is Capital not O&M)

RK U2 Carbon Injection

Company	LEG-9 #	Originated
Indiana Michigan Power Co. AEP Generating Co.	No	05/29/2007

Originator	Project Manager	CI Approval Required by
Michael H Huggett	Rodney E Moore	06/08/2007

Originator Phone No.	Project Manager Phone No.	Amount to be Authorized
8-200-2092 614-716-2092	8-200-1758 614-716-1758	$0.00

Approved by PMRG Board: Not Reviewed

Date Approved by PMRG Board:

Will material become obsolete as a result of this CI? No

If you have questions concerning Obsolete Material, please contact your Supply Chain Representative.

Budget (Direct Costs)	Prior Years	YR1 2006	YR2 2007	YR3 2008	YR4 2009	YR5+ 2010+	Total
Capital - Direct	0	0	0	0	0	0	0
Removal - Direct	0	0	0	0	0	0	0
Total Direct Budget	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0
Capital - Direct	0	0	0	0	0	0	0
Removal - Direct	0	0	0	0	0	0	0

Project / CPP / Program Amount Being Authorized

	Prior Years	2006	2007	2008	2009	2010+	Total
Capital - Direct	0	0	0	0	0	0	0
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs to be Authorized	0	0	0	0	0	0	0
Capital - Overheads	0	0	0	0	0	0	0
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	0	0	0	0	0	0
AFUDC	0	0	0	0	0	0	0
Amount Being Authorized	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Total Capital	0	0	0	0	0	0	0
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

For revisions to previously approved projects - Previous Amount Authorized

	Prior Years	2006	2007	2008	2009	2010+	**Total**
Capital - Direct	0	62,832	174,406	0	0	0	237,238
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs Previously Authorized	0	62,832	174,406	0	0	0	237,238
Capital - Overheads	0	5,906	16,394	0	0	0	22,300
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	5,906	16,394	0	0	0	22,300
AFUDC	0	288	3,410	0	0	0	3,698
Amount Previously Authorized	0	69,026	194,210	0	0	0	263,236
Associated O&M	0	0	0	0	0	0	0
Total Capital	0	69,026	194,210	0	0	0	263,236
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Incremental Amount to be Authorized (Calculated)

	Prior Years	2006	2007	2008	2009	2010+	**Total**
Capital - Direct	0	(62,832)	(174,406)	0	0	0	(237,238)
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs Difference	0	(62,832)	(174,406)	0	0	0	(237,238)
Capital - Overheads	0	(5,906)	(16,394)	0	0	0	(22,300)
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	(5,906)	(16,394)	0	0	0	(22,300)
AFUDC	0	(288)	(3,410)	0	0	0	(3,698)
Amount Difference	0	(69,026)	(194,210)	0	0	0	(263,236)
Associated O&M	0	0	0	0	0	0	0
Total Capital	0	(69,026)	(194,210)	0	0	0	(263,236)
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Ownership Unit Breakdown

Funding # / Company	*	**Prior Years**	**2006**	**2007**	**2008**	**2009**	**2010+**	**Total**
RK002ACI0	C	0	0	0	0	0	0	0
	R	0	0	0	0	0	0	0
Indiana Michigan Pwr Co - Gen **Total**		0	0	0	0	0	0	0
RK002ACIA	C	0	0	0	0	0	0	0
	R	0	0	0	0	0	0	0
AEG - Rockport **Total**		0	0	0	0	0	0	0

* C = Total Capital, R = Total Removals

Mark A Gray — 05/31/2007 07:41 AM EDT

Mark C McCullough — 06/05/2007 01:40 PM EDT

Kevin A Ricci — 06/06/2007 03:06 PM EDT

(on behalf of Don Eng, VP Project Field Services)

John M McManus	06/06/2007 03:13 PM EDT
Michael W Rencheck	06/06/2007 04:35 PM EDT
William L Sigmon	06/11/2007 10:47 AM EDT

Comments

Michael H Huggett - 05/29/2007 03:50:28 PM
This is a project cancellation request. This project scope will be performed under CI's RK001ACI0/RK001ACIA which are currently under revision.

Attachments

RK002ACI0 RK002ACIA PMRG Template Ver 02.xls

Regulatory Comments:

Kent D Curry - 05/29/2007 05:19:17 PM
If the Rockport Unit 2 investment is nonseverable (to be owned by the Rockport U2 Owner/Lessor), the investment would be reflected in lease payments made by I&M and AEG to the Owner /Lessor. I&M recovers its lease payments as O&M expense through formula rate billings pursuant to FERC-approved sales to I&M wholesale customers and Indiana and Michigan retail customer base rates, which may be adjusted through general rate cases the timing of which has not been precisely determined, although a 2007 Indiana filing is presently under consideration, offset in part by recoveries through I&M's Unit 2 power sale to Progress Energy. AEG recovers its lease payments as O&M expense through unit power sales to its customers, namely I&M and KPCo. I&M recovers its AEG purchased power costs through formula rate billings to wholesale customers and base rates and fuel and power supply cost recovery mechanisms, as applicable, in retail ratemaking.

If the Rockport Unit 2 investment is owned by I&M and AEG as a severable investment, such investment would be reflected in I&M's rate base through formula rate billings pursuant to FERC-approved sales to I&M wholesale customers and Indiana and Michigan retail customer base rates, which may be adjusted through general rate cases the timing of which has not been precisely determined, offset in part by recoveries through I&M's Unit 2 power sale to Progress Energy. AEG's rate base investment would be reflected in unit power sales to its customers, namely I&M and KPCo. I&M recovers its AEG purchased power costs through formula rate billings to wholesale customers and base rates and fuel and power supply cost recovery mechanisms, as applicable, in retail ratemaking.

Rockport Unit 2 Mercury Control Retrofit

Unit	Rockport 2	Funding Numbers	RK002ACI0		Date	29-May-07
			RK002ACIA		Project Mgr.	Rod Moore
Category Code	Environmental	Operating Company (s)	Indiana Michigan Power Co.	AEP Generating Co.	Unit Role	Base
Project Description	Complete a Phase 1 Feasibility Study for the installation of an Activated Carbon Injection (ACI) system at I&M's Rockport Units 1 and 2 (separate CI funding request was prepared for Unit 1). The purpose of this phase of the project will be to provide a comprehensive management report containing the necessary information to evaluate the feasibility of activated carbon injection for mercury control at Rockport and other PRB blended units. The primary objective of Phase 1 of the project is to obtain conceptual scope, cost, and schedule definition to support corporate management decisions regarding a mercury control strategy.					
Reason for Revsion	**Version 2:** The project will be completed as part of the RK U1 Mercury Control Retrofit (RK001ACI0 / RK001ACIA). Costs incurred under this project will be transferred to the Unit 1 project and once this CI revision is approved, the work orders associated with this project will be cancelled.					
Project Plan	The project will be executed using three project phases; each with distinct deliverables provided at the conclusion of each phase. Phase 1 of the project will include a Feasibility Study where the conceptual scope, cost, and schedule of the project will be established. The study cost is based on the order of magnitude estimated by Sargent & Lundy. The study will include a conceptual cost, scope, schedule and a list of recommended EPCC contractors, which can complete all required detail engineering, procurement, construction and commissioning activities. Phase 2 of the project will involve the development of final design, development of an EPCC specification and a bidding process. The EPCC specification and bidding process will be completed by the A/E firm, unless sufficient internal resources and commitment exist to support this project. At the conclusion of Phase 2, the detailed cost, scope, and schedule for the project will be established and a recommended EPCC contractor identified. Scope definition will be frozen at the conclusion of Phase 2, and a change control process will be implemented. Phase 3 of the project will involve the release of the EPCC contractor to perform detail engineering, fabrication, construction, and commissioning activities required to deliver the product of the project. The initiation of this project will occur through the submission and approval of a Capital Improvement (CI) funding request. Several fundamental questions must be answered prior to initiating the feasibility study to assure that the study considers the valid scope of work. First, the Sorbent Injection Test Program Report will be published by the Advanced Environmental Technology & Control group in the November 2006 timeframe. However, the scope of the study and the results which will be presented by the report are unclear at this time. Second, the decision to self-perform the feasibility study, or to contract with an A/E firm, has not been determined. The availability of internal resources to complete the study needs to be evaluated. In addition, there is a question whether added value could be provided by an A/E firm when much of the fundamental knowledge exists in AEP's AET&C Group. Third, there is a desire to develop a standardized equipment design which could be deployed at multiple plant sites. An evaluation is needed to determine whether a "single-solution" approach is valid. Finally, there is concern that the market for ACI based systems will become constrained by the common need by operators of coal-fired power plants to install similar mercury control measures prior to January 2010. The project plan will include a nominal two (2) month period to evaluate these issues and establish a firm basis for the Phase 1 feasibility study and identify the functioning organization (AEP or A/E).					
Schedule	Phase 1 will be completed by 3/2/2007. Phase 2 will be completed by 7/2/2007. Phase 3 will be completed by 7/7/2008. The Performance Test Plant Report and initiation of fleet-wide implementation will be completed by 9/1/2008. The operations date required for CAMR Phase 1 sites is 1/1/2010.					
Project Justification	In March 2005, the US EPA issued the Clean Air Mercury Rule (CAMR) to Cap and Reduce mercury emissions from coal-fired power plants. Rockport has been considered for mercury control as a part of AEP's mercury compliance strategy. Significant mercury co-benefit reductions are expected through the fleet-wide addition of SCR and FGD equipment prior to 2010. However, additional mercury reductions will be required on other Non-FGD/SCR plants to meet the fleet-wide target. All pollution control devices implemented under the CAMR Phase 1 must be in place by January 1, 2010. This project is an integral part of AEP's Mercury Compliance Strategy and will be required to reach the expected fleet-wide compliance targets. Current estimated total project cost is $27.3M.					
Alternatives Considered	Powdered activated carbon injection is currently considered the leading cost-effective means of mercury control.					

Capital Improvement Requisition Presented to the PMRG Board

Financial Analysis Summary	10 Year IRR		10 Year NPV		Simple Payback (Years)		Discount Rate
	N/A		N/A		N/A		N/A
Economic Analysis Assumptions	Availability Improvement		Capacity Improvement		Fuel Efficiency		Cost Reduction / Avoided Cost
	N/A		N/A		N/A		N/A

	Year	2005	2006	2007	2008	2009	Total ($)
Cash Flow (Requested) Direct Costs	Amount Budgeted						$0
	Material						$0
	Labor		$0	$0			$0
	Other		$0	$0			$0
	Removal						$0
	Total Direct	$0	$0	$0	$0	$0	$0
	Delta in Budget vs Request	$0	$0	$0	$0	$0	$0
Loaded Costs	Amount to be Authorized		$0	$0			$0
	Associated O&M	-	-				

Additional Notes:
Currently there is no cost savings associated with a reduction in mercury emissions.

	Version 1	Version 2	Delta
Material	-	-	-
Labor	59,400	-	(59,400)
Other	177,837	-	(177,837)
Indirect	25,999	-	(25,999)
Total	**263,236**	**-**	**(263,236)**

Approved by the PMRG Board

KPSC Case No. 2014-00396
Staff's Second Set of Data Requests
Dated January 29,2015
Item No. 41
Attachment 1
Page 99 of 136

Unit: WSREG **Project ID:** RK002ACI0 **Description:** RK U2 Carbon Injection

Delete **Last OPRID:** S134130 Michael H Huggett **Last Update Dttm:** 05/29/07 2:34:57PM View C

Capital Improvement Estimate

Version: 2 **Est. Status:** Initiated **CPP/Program:**

***Funding Proj Type:** 111283 I&M

***Start Date:** 09/19/2006 ***In Service:** 06/01/2007

***Sub Juris ID:** IM_G I&M

***Environ Code:** Air Pollution

Mandatory Reason: Environmental

***Major Location:** 82 Rockport Generating Plant

BU Approver:

Project Manager: 4208764 Moore,Rodney E

Approval Date:

Scores Risks Rates Recalc Approve Reject

Cost Categories	TOTAL	2006	2007	2008	2009
Capital					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Expense					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal Overheads					

Costs Calcs - If checked, override amount is displayed.						
Total Direct Capital						
Total Direct Removal						
Total Direct						
Total Dir Cap+Fleet+Fringe						
Cap Overheads - Override	☑					
AFUDC Basis						
AFUDC Debt - Override	☑					
AFUDC Equity - Override	☑					
Total Capital						
Total Removal						
Total Approved Project Cost						
Total Expense						
CIAC/Other Credits						
Total Project Cost						
Accum Total Project Cost						
Accum Tot Cap Less CIAC						

Other Categories	TOTAL	2007	2008	2009	2010
Market Revenue					
3rd Party Revenue					
Total Revenue					
Savings/Avoided Costs					
Credits					
Total Project Benefits					
Incremental Costs					
EBITDA (Margin)					
Tax Depreciation					
EBIT					
Accum Tax Depreciation					
Net Tax Value					
Book Depreciation					
Accum Book Depreciation					
Net Book Value					
Terminal Value					
Property Tax					
Taxable Income					
Tax (composite)					
After Tax Cash Flow					
Retirement					

Salvage					
Total Project Cash Flows					
Accum Total Project Cash Flows					

Version: 1 **Est. Status:** Approved **CPP/Program:** **Funding Proj Type:** 111283 I&M

Start Date: 09/19/2006 **In Service:** 12/31/2009 **Sub Juris ID:** IM_G I&M

Environ Code: Air Pollution **Mandatory Reason:** Environmental

Major Location: 82 Rockport Generating Plant **BU Approver:** 4202524 Sign

Project Manager: 9105248 Bollinger,Robert B **Approval Date:** 10/06/2006

Scores Risks Rates

Cost Categories	TOTAL	2006	2007	2008	2009
Capital					
Internal Labor	88,919.00	31,416.00	57,503.00		
Outside Services	29,700.00		29,700.00		
Material					
Other					
Fleet					
Fringes					
Expense					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal Overheads					

Costs Calcs - If checked, override amount is displayed.						
Total Direct Capital		118,619.00	31,416.00	87,203.00		
Total Direct Removal						
Total Direct		118,619.00	31,416.00	87,203.00		
Total Dir Cap+Fleet+Fringe		118,619.00	31,416.00	87,203.00		
Cap Overheads - Override	☑	11,150.00	2,953.00	8,197.00		
AFUDC Basis			34,369.00	129,913.00	131,618.00	131,618.00
AFUDC Debt - Override	☑	1,849.00	144.00	1,705.00		
AFUDC Equity - Override	☑					

Total Capital		131,618.00	34,513.00	97,105.00		
Total Removal						
Total Approved Project Cost		131,618.00	34,513.00	97,105.00		
Total Expense						
CIAC/Other Credits						
Total Project Cost		131,618.00	34,513.00	97,105.00		
Accum Total Project Cost			34,513.00	131,618.00	131,618.00	131,618.00
Accum Tot Cap Less CIAC			34,513.00	131,618.00	131,618.00	131,618.00

Other Categories	TOTAL	2009	2010	2011	2012
Market Revenue					
3rd Party Revenue					
Total Revenue					
Savings/Avoided Costs					
Credits					
Total Project Benefits					
Incremental Costs					
EBITDA (Margin)					
Tax Depreciation	69,960.24	4,935.68	9,501.50	8,788.13	8,130.0
EBIT	-69,960.24	-4,935.68	-9,501.50	-8,788.13	-8,130.0
Accum Tax Depreciation		4,935.68	14,437.18	23,225.31	31,355.3
Net Tax Value		126,682.32	117,180.82	108,392.69	100,262.6
Book Depreciation	47,006.40	4,700.64	4,700.64	4,700.64	4,700.6
Accum Book Depreciation		4,700.64	9,401.28	14,101.92	18,802.5
Net Book Value		126,917.36	122,216.72	117,516.08	112,815.4
Terminal Value	76,118.68				
Property Tax	25,053.49	1,599.16	3,079.86	2,961.41	2,842.9
Taxable Income	-95,013.73	-6,534.84	-12,581.36	-11,749.54	-10,972.9
Tax (composite)	-35,155.09	-2,417.89	-4,655.10	-4,347.33	-4,060.0
After Tax Cash Flow	10,101.60	818.73	1,575.24	1,385.92	1,217.0
Retirement					
Salvage					
Total Project Cash Flows	-45,397.72	-130,799.27	1,575.24	1,385.92	1,217.0
Accum Total Project Cash Flows		-130,799.27	-129,224.03	-127,838.11	-126,621.0

Save Return to Search Refresh

Business Unit: WSREG Wholesale Regulated

***Project ID:** RK002ACI0

***Description:** RK U2 Carbon Injection

Project Summary

Integration: ALL_PROJECTS Default - All Projects

Project Type: MPHCS Major Environmental Hardware

***Project Category:** BBC-M Boiler-Mercury

Project Class: GEN Generation

Project Status: 2 Open

AEP Work Orders

ABD	RD
NR	SCNA
PC	SCNM
PCGEN	SCWO
OPWO	EXPWO

Description

View All |< 1 of 1 >|

Date/Time Stamp: 09/01/06 2:29:04PM

User ID: S134130

***Description:**

RK U2 Carbon Injection

Long Description:

Save | Return to Search | Refresh

Unit: WSREG **Project ID:** RK002ACI0 **Description:** RK U2 Carbon Injection

***Tree Name:** WHOLESALE_REG

***Effective Date of Tree:** 01/01/1901

***Parent Tree Node:** 000000174

***GL Business Unit:** 132 Indiana Michigan Pwr Co - Gen

CI Value: RK002ACI0 RK U2 Carbon Injection

***Project Initiator:** S134130 Michael H Huggett

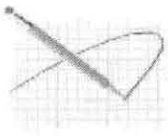
In Service Date: 06/01/2007

Sub Jurisdiction ID: IM_G I&M Generation

Summary Switch

- (•) Allow Workorders(This is a Detail Project)
- ( ) Do not Allow Workorders(This is a Parent Project)

Save | Return to Search | Refresh



CI - LI Routing
Sent by: William L Sigmon

06/11/2007 10:47 AM

Please respond to
CI - LI Routing

To Helen J Murray/OR1/AEPIN@AEPIN, James F Martin/OR1/AEPIN@AEPIN, John F Torpey/OR4/AEPIN@AEPIN, Patricia D
cc
bcc
Subject CI/LI #RK002ACI0;RK002ACIA has been Approved.

CI/LI #RK002ACI0;RK002ACIA (RK U2 Carbon Injection) is approved and available for review at your convenience.

To review or act upon the request, please follow this link. ->>

Date June 11, 2007

Company	CI/LI/CPP/Program Number	Version
AEP Generating Co.	RK002ACIA	2

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PC 6-11-2007		PC 6-11-2007

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Martin		Related I&M Joint Plant CI#RK002ACI0
2	R. E. Munczinski		6/12/07
	S. Smith		
	H. Koeppel		
	J. Hamrock		
	S. Tomasky		
	M. K. Nazar		
	S. N. Smith		
	N. K. Akins		
	B. Bond (SWEPCO T&D)		
	T. M. Hagan		
	R. P. Powers		
	M. Heyeck		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
	M. G. Morris		
3	Paula Cahill - 28th floor Ext 2494		
		6-13-2007	Approved in PeopleSoft
			Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Pat Bachman - 28th Floor - Ext 2888

AEP Printing Services:

Scanned File Name: AEP Generating Co. RK002ACIA Version 2.pdf

Please return to Capital Budgeting, 28th Floor 1RP

Generation CI/LI Approval Routing Document

Status: Approved

Last populated: 05/29/2007 03:49 PM

Plant	Unit	Funding Project #	Ver. #	Project Type
Rockport	2	RK002ACI0	2	Project
		RK002ACIA	2	

Project Title: RK U2 Carbon Injection

Outage Code: (if necessary)

In-service date: 6/1/2007

Brief Description of Project (sufficient to determine that the project is Capital not O&M)

RK U2 Carbon Injection

Company	LEG-9 #	Originated
Indiana Michigan Power Co. AEP Generating Co.	No	05/29/2007

Originator	Project Manager	CI Approval Required by
Michael H Huggett	Rodney E Moore	06/08/2007

Originator Phone No.	Project Manager Phone No.	Amount to be Authorized
8-200-2092 614-716-2092	8-200-1758 614-716-1758	$0.00

Approved by PMRG Board: Not Reviewed

Date Approved by PMRG Board:

Will material become obsolete as a result of this CI? No

If you have questions concerning Obsolete Material, please contact your Supply Chain Representative.

Budget (Direct Costs)	Prior Years	YR1 2006	YR2 2007	YR3 2008	YR4 2009	YR5+ 2010+	Total
Capital - Direct	0	0	0	0	0	0	0
Removal - Direct	0	0	0	0	0	0	0
Total Direct Budget	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0
Capital - Direct	0	0	0	0	0	0	0
Removal - Direct	0	0	0	0	0	0	0

Project / CPP / Program Amount Being Authorized

	Prior Years	2006	2007	2008	2009	2010+	Total
Capital - Direct	0	0	0	0	0	0	0
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs to be Authorized	0	0	0	0	0	0	0
Capital - Overheads	0	0	0	0	0	0	0
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	0	0	0	0	0	0
AFUDC	0	0	0	0	0	0	0
Amount Being Authorized	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Total Capital	0	0	0	0	0	0	0
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

For revisions to previously approved projects - Previous Amount Authorized

	Prior Years	2006	2007	2008	2009	2010+	**Total**
Capital - Direct	0	62,832	174,406	0	0	0	237,238
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs Previously Authorized	0	62,832	174,406	0	0	0	237,238
Capital - Overheads	0	5,906	16,394	0	0	0	22,300
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	5,906	16,394	0	0	0	22,300
AFUDC	0	288	3,410	0	0	0	3,698
Amount Previously Authorized	0	69,026	194,210	0	0	0	263,236
Associated O&M	0	0	0	0	0	0	0
Total Capital	0	69,026	194,210	0	0	0	263,236
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Incremental Amount to be Authorized (Calculated)

	Prior Years	2006	2007	2008	2009	2010+	**Total**
Capital - Direct	0	(62,832)	(174,406)	0	0	0	(237,238)
Removal - Direct	0	0	0	0	0	0	0
Total Direct Costs Difference	0	(62,832)	(174,406)	0	0	0	(237,238)
Capital - Overheads	0	(5,906)	(16,394)	0	0	0	(22,300)
Removal - Overheads	0	0	0	0	0	0	0
Overheads	0	(5,906)	(16,394)	0	0	0	(22,300)
AFUDC	0	(288)	(3,410)	0	0	0	(3,698)
Amount Difference	0	(69,026)	(194,210)	0	0	0	(263,236)
Associated O&M	0	0	0	0	0	0	0
Total Capital	0	(69,026)	(194,210)	0	0	0	(263,236)
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Ownership Unit Breakdown

Funding # / Company	*	**Prior Years**	**2006**	**2007**	**2008**	**2009**	**2010+**	**Total**
RK002ACI0	C	0	0	0	0	0	0	0
	R	0	0	0	0	0	0	0
Indiana Michigan Pwr Co - Gen **Total**		0	0	0	0	0	0	0
RK002ACIA	C	0	0	0	0	0	0	0
	R	0	0	0	0	0	0	0
AEG - Rockport **Total**		0	0	0	0	0	0	0

* C = Total Capital, R = Total Removals

Mark A Gray — 05/31/2007 07:41 AM EDT

Mark C McCullough — 06/05/2007 01:40 PM EDT

Kevin A Ricci — 06/06/2007 03:06 PM EDT

(on behalf of Don Eng, VP Project Field Services)

John M McManus	06/06/2007 03:13 PM EDT
Michael W Rencheck	06/06/2007 04:35 PM EDT
William L Sigmon	06/11/2007 10:47 AM EDT

Comments

Michael H Huggett - 05/29/2007 03:50:28 PM
This is a project cancellation request. This project scope will be performed under CI's RK001ACI0/RK001ACIA which are currently under revision.

Attachments

RK002ACI0 RK002ACIA PMRG Template Ver 02.xls

Regulatory Comments:

Kent D Curry - 05/29/2007 05:19:17 PM
If the Rockport Unit 2 investment is nonseverable (to be owned by the Rockport U2 Owner/Lessor), the investment would be reflected in lease payments made by I&M and AEG to the Owner /Lessor. I&M recovers its lease payments as O&M expense through formula rate billings pursuant to FERC-approved sales to I&M wholesale customers and Indiana and Michigan retail customer base rates, which may be adjusted through general rate cases the timing of which has not been precisely determined, although a 2007 Indiana filing is presently under consideration, offset in part by recoveries through I&M's Unit 2 power sale to Progress Energy. AEG recovers its lease payments as O&M expense through unit power sales to its customers, namely I&M and KPCo. I&M recovers its AEG purchased power costs through formula rate billings to wholesale customers and base rates and fuel and power supply cost recovery mechanisms, as applicable, in retail ratemaking.

If the Rockport Unit 2 investment is owned by I&M and AEG as a severable investment, such investment would be reflected in I&M's rate base through formula rate billings pursuant to FERC-approved sales to I&M wholesale customers and Indiana and Michigan retail customer base rates, which may be adjusted through general rate cases the timing of which has not been precisely determined, offset in part by recoveries through I&M's Unit 2 power sale to Progress Energy. AEG's rate base investment would be reflected in unit power sales to its customers, namely I&M and KPCo. I&M recovers its AEG purchased power costs through formula rate billings to wholesale customers and base rates and fuel and power supply cost recovery mechanisms, as applicable, in retail ratemaking.

Capital Improvement Requisition Presented to the PMRG Board

Rockport Unit 2 Mercury Control Retrofit

Unit	Rockport 2	Funding Numbers	RK002ACI0 RK002ACIA		Date Project Mgr.	29-May-07 Rod Moore
Category Code	Environmental	Operating Company (s)	Indiana Michigan Power Co.	AEP Generating Co.	Unit Role	Base
Project Description	Complete a Phase 1 Feasibility Study for the installation of an Activated Carbon Injection (ACI) system at I&M's Rockport Units 1 and 2 (separate CI funding request was prepared for Unit 1). The purpose of this phase of the project will be to provide a comprehensive management report containing the necessary information to evaluate the feasibility of activated carbon injection for mercury control at Rockport and other PRB blended units. The primary objective of Phase 1 of the project is to obtain conceptual scope, cost, and schedule definition to support corporate management decisions regarding a mercury control strategy.					
Reason for Revsion	**Version 2:** The project will be completed as part of the RK U1 Mercury Control Retrofit (RK001ACI0 / RK001ACIA). Costs incurred under this project will be transferred to the Unit 1 project and once this CI revision is approved, the work orders associated with this project will be cancelled.					
Project Plan	The project will be executed using three project phases; each with distinct deliverables provided at the conclusion of each phase. Phase 1 of the project will include a Feasibility Study where the conceptual scope, cost, and schedule of the project will be established. The study cost is based on the order of magnitude estimated by Sargent & Lundy. The study will include a conceptual cost, scope, schedule and a list of recommended EPCC contractors, which can complete all required detail engineering, procurement, construction and commissioning activities. Phase 2 of the project will involve the development of final design, development of an EPCC specification and a bidding process. The EPCC specification and bidding process will be completed by the A/E firm, unless sufficient internal resources and commitment exist to support this project. At the conclusion of Phase 2, the detailed cost, scope, and schedule for the project will be established and a recommended EPCC contractor identified. Scope definition will be frozen at the conclusion of Phase 2, and a change control process will be implemented. Phase 3 of the project will involve the release of the EPCC contractor to perform detail engineering, fabrication, construction, and commissioning activities required to deliver the product of the project. The initiation of this project will occur through the submission and approval of a Capital Improvement (CI) funding request. Several fundamental questions must be answered prior to initiating the feasibility study to assure that the study considers the valid scope of work. First, the Sorbent Injection Test Program Report will be published by the Advanced Environmental Technology & Control group in the November 2006 timeframe. However, the scope of the study and the results which will be presented by the report are unclear at this time. Second, the decision to self-perform the feasibility study, or to contract with an A/E firm, has not been determined. The availability of internal resources to complete the study needs to be evaluated. In addition, there is a question whether added value could be provided by an A/E firm when much of the fundamental knowledge exists in AEP's AET&C Group. Third, there is a desire to develop a standardized equipment design which could be deployed at multiple plant sites. An evaluation is needed to determine whether a "single-solution" approach is valid. Finally, there is concern that the market for ACI based systems will become constrained by the common need by operators of coal-fired power plants to install similar mercury control measures prior to January 2010. The project plan will include a nominal two (2) month period to evaluate these issues and establish a firm basis for the Phase 1 feasibility study and identify the functioning organization (AEP or A/E).					
Schedule	Phase 1 will be completed by 3/2/2007. Phase 2 will be completed by 7/2/2007. Phase 3 will be completed by 7/7/2008. The Performance Test Plant Report and initiation of fleet-wide implementation will be completed by 9/1/2008. The operations date required for CAMR Phase 1 sites is 1/1/2010.					
Project Justification	In March 2005, the US EPA issued the Clean Air Mercury Rule (CAMR) to Cap and Reduce mercury emissions from coal-fired power plants. Rockport has been considered for mercury control as a part of AEP's mercury compliance strategy. Significant mercury co-benefit reductions are expected through the fleet-wide addition of SCR and FGD equipment prior to 2010. However, additional mercury reductions will be required on other Non-FGD/SCR plants to meet the fleet-wide target. All pollution control devices implemented under the CAMR Phase 1 must be in place by January 1, 2010. This project is an integral part of AEP's Mercury Compliance Strategy and will be required to reach the expected fleet-wide compliance targets. Current estimated total project cost is $27.3M.					
Alternatives Considered	Powdered activated carbon injection is currently considered the leading cost-effective means of mercury control.					

Approved by the PMRG Board _____

Capital Improvement Requisition Presented to the PMRG Board

Financial Analysis Summary	10 Year IRR		10 Year NPV		Simple Payback (Years)		Discount Rate
	N/A		N/A		N/A		N/A
Economic Analysis Assumptions	Availability Improvement		Capacity Improvement		Fuel Efficiency		Cost Reduction / Avoided Cost
	N/A		N/A		N/A		N/A

	Year	2005	2006	2007	2008	2009	Total ($)
Cash Flow (Requested) Direct Costs	Amount Budgeted						$0
	Material						$0
	Labor		$0	$0			$0
	Other		$0	$0			$0
	Removal						$0
	Total Direct	$0	$0	$0	$0	$0	$0
	Delta in Budget vs Request	$0	$0	$0	$0	$0	$0
Loaded Costs	Amount to be Authorized		$0	$0			$0
	Associated O&M	-	-				

Additional Notes:
Currently there is no cost savings associated with a reduction in mercury emissions.

	Version 1	Version 2	Delta
Material	-	-	-
Labor	59,400	-	(59,400)
Other	177,837	-	(177,837)
Indirect	25,999	-	(25,999)
Total	**263,236**	**-**	**(263,236)**

Approved by the PMRG Board

Unit: WSREG **Project ID:** RK002ACIA **Description:** RK U2 Carbon Injection AEG

Delete **Last OPRID:** S134130 Michael H Huggett **Last Update Dttm:** 05/29/07 2:36:09PM View C

Capital Improvement Estimate

Version: 2 **Est. Status:** Initiated **CPP/Program:**

***Funding Proj Type:** 111281 AEC

***Start Date:** 09/19/2006 ***In Service:** 06/01/2007

***Sub Juris ID:** IM_AEG_G I&M

***Environ Code:** Air Pollution

Mandatory Reason: Environmental

***Major Location:** 82 Rockport Generating Plant

BU Approver:

Project Manager: 4208764 Moore,Rodney E

Approval Date:

Scores Risks Rates Recalc Approve Reject

Cost Categories	TOTAL	2006	2007	2008	2009
Capital					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Expense					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal Overheads					

KPSC Case No. 2014-00396
Staff's Second Set of Data Requests
Dated January 29,2015
Item No. 41
Attachment 1
Page 113 of 136

Costs Calcs - If checked, override amount is displayed.						
Total Direct Capital						
Total Direct Removal						
Total Direct						
Total Dir Cap+Fleet+Fringe						
Cap Overheads - Override	☑					
AFUDC Basis						
AFUDC Debt - Override	☑					
AFUDC Equity - Override	☑					
Total Capital						
Total Removal						
Total Approved Project Cost						
Total Expense						
CIAC/Other Credits						
Total Project Cost						
Accum Total Project Cost						
Accum Tot Cap Less CIAC						

Other Categories	TOTAL	2007	2008	2009	2010
Market Revenue					
3rd Party Revenue					
Total Revenue					
Savings/Avoided Costs					
Credits					
Total Project Benefits					
Incremental Costs					
EBITDA (Margin)					
Tax Depreciation					
EBIT					
Accum Tax Depreciation					
Net Tax Value					
Book Depreciation					
Accum Book Depreciation					
Net Book Value					
Terminal Value					
Property Tax					
Taxable Income					
Tax (composite)					
After Tax Cash Flow					
Retirement					

Salvage					
Total Project Cash Flows					
Accum Total Project Cash Flows					

Version: 1 **Est. Status:** Approved **CPP/Program:** **Funding Proj Type:** 111281 AEG

Start Date: 09/19/2006 **In Service:** 12/31/2009 **Sub Juris ID:** IM_AEG_G I&M

Environ Code: Air Pollution **Mandatory Reason:** Environmental

Major Location: 82 Rockport Generating Plant **BU Approver:** 4202524 Sign

Project Manager: 9105248 Bollinger,Robert B **Approval Date:** 10/06/2006

Scores Risks Rates

Cost Categories	TOTAL	2006	2007	2008	2009
Capital					
Internal Labor	88,919.00	31,416.00	57,503.00		
Outside Services	29,700.00		29,700.00		
Material					
Other					
Fleet					
Fringes					
Expense					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal					
Internal Labor					
Outside Services					
Material					
Other					
Fleet					
Fringes					
Removal Overheads					
Costs Calcs - If checked, override amount is displayed.					
Total Direct Capital		118,619.00	31,416.00	87,203.00		
Total Direct Removal						
Total Direct		118,619.00	31,416.00	87,203.00		
Total Dir Cap+Fleet+Fringe		118,619.00	31,416.00	87,203.00		
Cap Overheads - Override	☑	11,150.00	2,953.00	8,197.00		
AFUDC Basis			34,369.00	129,913.00	131,618.00	131,618.00
AFUDC Debt - Override	☑	1,849.00	144.00	1,705.00		
AFUDC Equity - Override	☑					

Total Capital		131,618.00	34,513.00	97,105.00		
Total Removal						
Total Approved Project Cost		131,618.00	34,513.00	97,105.00		
Total Expense						
CIAC/Other Credits						
Total Project Cost		131,618.00	34,513.00	97,105.00		
Accum Total Project Cost			34,513.00	131,618.00	131,618.00	131,618.00
Accum Tot Cap Less CIAC			34,513.00	131,618.00	131,618.00	131,618.00

Other Categories	TOTAL	2009	2010	2011	2012
Market Revenue					
3rd Party Revenue					
Total Revenue					
Savings/Avoided Costs					
Credits					
Total Project Benefits					
Incremental Costs					
EBITDA (Margin)					
Tax Depreciation	69,960.24	4,935.68	9,501.50	8,788.13	8,130.0
EBIT	-69,960.24	-4,935.68	-9,501.50	-8,788.13	-8,130.0
Accum Tax Depreciation		4,935.68	14,437.18	23,225.31	31,355.3
Net Tax Value		126,682.32	117,180.82	108,392.69	100,262.6
Book Depreciation	47,006.40	4,700.64	4,700.64	4,700.64	4,700.6
Accum Book Depreciation		4,700.64	9,401.28	14,101.92	18,802.5
Net Book Value		126,917.36	122,216.72	117,516.08	112,815.4
Terminal Value	76,118.68				
Property Tax	24,655.82	1,573.78	3,030.97	2,914.40	2,797.8
Taxable Income	-94,616.06	-6,509.46	-12,532.47	-11,702.53	-10,927.8
Tax (composite)	-35,007.94	-2,408.50	-4,637.01	-4,329.94	-4,043.3
After Tax Cash Flow	10,352.12	834.72	1,606.04	1,415.54	1,245.4
Retirement					
Salvage					
Total Project Cash Flows	-45,147.20	-130,783.28	1,606.04	1,415.54	1,245.4
Accum Total Project Cash Flows		-130,783.28	-129,177.24	-127,761.70	-126,516.2

Save Return to Search Refresh

Business Unit: WSREG Wholesale Regulated

***Project ID:** RK002ACIA

***Description:** RK U2 Carbon Injection AEG

Project Summary

Integration: ALL_PROJECTS Default - All Projects

Project Type: MPHCS Major Environmental Hardware

***Project Category:** BBC-M Boiler-Mercury

Project Class: GEN Generation

Project Status: 2 Open

AEP Work Orders

ABD	RD
NR	SCNA
PC	SCNM
PCGEN	SCWO
OPWO	EXPWO

Description

View All |< 1 of 1 >|

Date/Time Stamp: 09/01/06 2:31:05PM

User ID: S134130

***Description:**

RK U2 Carbon Injection AEG

Long Description:

Save | Return to Search | Refresh

Unit: WSREG **Project ID:** RK002ACIA **Description:** RK U2 Carbon Injection AEG

***Tree Name:** WHOLESALE_REG

***Effective Date of Tree:** 01/01/1901

***Parent Tree Node:** 000000174

***GL Business Unit:** 153 AEG - Rockport

CI Value: RK002ACIA RK U2 Carbon Injection AEG

***Project Initiator:** S134130 Michael H Huggett

In Service Date: 06/01/2007

Sub Jurisdiction ID: IM_AEG_G I&M AEP Generating

Summary Switch

- (•) Allow Workorders(This is a Detail Project)
- ( ) Do not Allow Workorders(This is a Parent Project)

Save | Return to Search | Refresh

CI - LI Routing
Sent by: William L Sigmon

06/11/2007 10:47 AM

Please respond to
CI - LI Routing

To Helen J Murray/OR1/AEPIN@AEPIN, James F Martin/OR1/AEPIN@AEPIN, John F Torpey/OR4/AEPIN@AEPIN, Patricia D
cc
bcc
Subject CI/LI #RK002ACI0;RK002ACIA has been Approved.

CI/LI #RK002ACI0;RK002ACIA (RK U2 Carbon Injection) is approved and available for review at your convenience.

To review or act upon the request, please follow this link. ->>

Date February 20, 2009

Company	CI/LI/CPP/Program Number	Version
AEP System	ACICAMR00	4

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PB 02/20/09	Dollars budgeted under RK80ACI9	PB 02/20/09

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
1	J. Martin	JFM 2/23/09	
2	L.L. Dieck	LLD 2/25/09	
	H. Koeppel		
	M. Heyeck		
	S. Tomasky		
	M. W. Rencheck		
	S.N. Smith		
	N. K. Akins	See attached	
	R. E. Munczinski		
	D. E. Welch		
	B. X. Tierney (East > $10 million)		
	V. McCellon-Allen (West > $10 million)		
	R. P. Powers		
	C. L. English		
	Buckeye Power Approval		
3	M. G. Morris	[signature] 2/26/09	
4	Pat Bachman - 28th floor Ext 2888		
		02/26/09	Approved in PeopleSoft
		March 2009	Month Included in Board Package

Alternate CP&B Contacts:
Christine Gaston - 28th Floor - Ext 5994
Bobby Myers - 28th Floor - Ext 2642

Scanned File Name: AEP System ACICAMR00 Version 4.pdf

CAPITAL PROGRAM APPROVAL REQUISITION

Company: AEP System **Program Number:** ACICAMR00

Authorization Type: Capital Program Version Number: 4

Business Line: Generation

Location: Multiple Generating Plant Locations

Project Title: Activated Carbon Injection Program

Business Reason: Environmental, Safety and Health

Brief Description: Complete the Activated Carbon Injection System (ACIS) Program for reduction of mercury emissions at Rockport generation plant only After the CAMR was vacated by the DC Appeals Court on Feb. 8, 2008, the installation of ACIS islands at the following seven plants has been suspended, pending new legislation: Northeastern, Sporn, Clinch River, Kammer, Tanners Creek, Pirkey and Oklaunion.

Regulatory Cost Recovery: See Page 3

Project Dates:	**Start:**	**Completion:**	**In-Service:**
	12/01/2006	01/01/2010	01/01/2010

Expenditure to be Authorized (fully loaded)

	Capital ($)	Removal ($)	Total ($)
Previously Approved Amount	$170,000,000	0	$170,000,000
This Submission	($134,667,408)	0	($134,667,408)
Total ($)	**$35,332,592**	**$0**	**$35,332,592**

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior Vice President	McCullough, M.	see attached	
$ 10m ≤ amt < $ 20m	Executive Vice President	Akins, N.	see attached	
amt ≥ $ 20m	Chairman, President & CEO	Morris, M.		2.26.09
CP&B Review	Senior Vice President	Dieck, L.		

2009 Direct Cost Budget Availability for this Authorization: $16.2M In Forecast $ N/A Offset

If offset, indicate source and amount:

Requested future year amounts are included in or offset within the Strategic Plan Capital Forecast.

CAPITAL PROGRAM APPROVAL REQUISITION

Cash Flow (fully loaded)

Year	Prior Years	2009	2010	2011	Future Years	Total ($)
Capital	21,881,911	13,450,681	0			35,332,592
Removal						
Total to be Authorized	21,881,912	13,450,681	0			35,332,592
Assoc. O & M						

Note: Associated O & M is not approved with this requisition. Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

Financial Analysis Summary

The decision to install this technology was made in the context of an AEP system wide environmental compliance analysis which identified that this project was a critical element in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the multi-emissions compliance optimization model (MECO), a unique mixed integer programming model which solves for the least cost environmental compliance plan. The model considers power and emission allowance markets, load demand forecast, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. This proprietary model is a sophisticated analytic tool that allows the company to systematically weigh costs and risks of a wide variety of options and allows simultaneous optimization across multi-emissions (SO2, NOx, mercury and CO2).

Program CIs

CI Number	Operating Company/Plant	Previously Approved Amount ($)		This Submission ($)		Subtotal ($)		Total Cost ($)
		Capital	Rem	Capital	Rem	Capital	Rem	
RK001ACIA	AEG – Rockport	12,297,644	0	1,446,146	0	13,743,790	0	**13,743,790**
RK001ACI0	I&M – Rockport	12,297,644	0	1,446,146	0	13,743,790	0	**13,743,790**
TC001ACI0	I&M -Tanners Crk	35,392,076	0	(35,235,489)	0	156,587	0	**156,587**
SP001ACIA	APCO -Sporn 1,3	9,491,227	0	(9,330,363)	0	160,864	0	**160,864**
SP001ACIO	OPCO - Sporn 2,4	9,491,227	0	(9,330,363)	0	160,864	0	**160,864**
CR001ACI0	APCO - Clinch River	19,054,784	0	(19,019,440)	0	35,344	0	**35,344**
PRK01ACI0	SWEPCO - Pirkey	17,005,445	0	(12,299,438)	0	4,706,007	0	**4,706,007**
NE003ACI0	PSO - Northeastern	18,924,694	0	(16,377,911)	0	2,546,783	0	**2,546,783**
OKL01ACI0	PSO - Oklaunion	3,750,178	0	(3,745,404)	0	4,774	0	**4,774**
OKN01ACI0	TNC - Oklaunion	13,296,085	0	(13,279,159)	0	16,926	0	**16,926**
KM001ACI0	OPCO - Kammer	18,998,996	0	(18,942,133)	0	56,863	0	**56,863**
Total Cost($)		**170,000,000**	**$0**	**(134,667,408)**	**$0**	**35,332,592**	**$0**	**35,332,592**

Version 4: Project Justification

Approval of Version 4 of CI ACICAMR00 will authorize the **reduction** of $134,667,408 from the ACIS Program funding. On Feb. 8, 2008, the District of Columbia Circuit Court of Appeals issued a decision which vacated the EPA's Clean Air Mercury Rule (CAMR). The CAMR required that coal-fired power plants regulate mercury emissions. The 2010 CAMR compliance deadline no longer applies. A new deadline under the previous Maximum Achievable Control Technology (MACT) standard now requires

CAPITAL PROGRAM APPROVAL REQUISITION

new rulemaking. AEP Management has decided to suspend and no longer fund the ACIS Program activities at Pirkey, Sporn, Clinch River, Tanners Creek, Kammer, Northeastern, and Oklaunion. The Program is continuing at Rockport. Activated carbon injection for mercury control is widely accepted in the industry as a viable technology and it is likely to be a part of our future fleet compliance plan. Continuing with this ACI ESP project will demonstrate the capability of this technology on a long-term basis and will result in data that will be of value both to AEP's future compliance planning effort and to AEP as we work with EPA when new mercury rulemaking begins. Once new mercury regulations have been approved, a determination will be made of the costs spent to date on the suspended projects and they will either be completed or expensed.

Version 3 authorized the total required funding of $170,000,000 for implementation of the ACIS Program consistent with the AEP Environmental Compliance Plan to meet Phase I of the Clean Air Mercury Rule (CAMR) requirements.

Versions 1 and 2 of this requisition authorized the Phase I feasibility studies and the Phase IIA conceptual engineering/design phase of this project, respectively.

Other Alternatives Considered

The MECO model was used to evaluate alternatives, such as the addition of a pulse-jet baghouse, SCR/WFGD combinations, and ACI ESP for mercury capture. With the large capital investment required for baghouse or SCR/WFGD installations, ACI ESP was selected as the least-cost option for mercury removal at these plants. The program team continues to investigate the least cost implementation of the overall ACIS Program. The areas of investigation that are considered by the team to have a potential to impact the total program scope include coal washing and/or possible coal/boiler additives at selected units. Further program adjustments may also result from comparing actual Hg monitoring data to baseline data to optimize the ACI program selection.

Conclusion

The 2010 CAMR compliance deadline no longer applies. A new deadline under the previous Maximum Achievable Control Technology (MACT) standard now requires new rulemaking. AEP Management has decided to suspend and no longer fund the ACIS Program with the exception of Rockport plant. This project is an integral part of AEP's Mercury Compliance Strategy and will be required to attain the expected fleet-wide compliance targets. In March 2005, the US EPA issued the Clean Air Mercury Rule (CAMR) to Cap and Reduce mercury emissions from coal-fired power plants. These nine units have been considered for mercury control as a part of AEP's mercury compliance strategy. Significant mercury co-benefit reductions are expected through the fleet-wide addition of SCR and FGD equipment prior to 2010. However, additional mercury reductions will be required on non-FGD/SCR plants to meet the fleet target.

Regulatory Cost Recovery

Costs incurred due to the installation of ACI at the Rockport plant will be recovered as defined by the outcome of I&M's planned application for a Certificate of Public Convenience and Necessity (CPCN). The petition for the CPCN is expected to be filed in early 2009, with a decision from the Indiana Commission likely to follow approximately six months later. Because ACI will reduce mercury at the Rockport plant, it qualifies as Clean Coal Technology under Indiana code. Capital and O&M for Clean Coal Technology projects are eligible for financial incentives and timely cost recovery as determined by the Commission through CPCN hearings.

The work orders for the remaining projects will be suspended in accordance with the AEP Property Accounting procedure that will halt accumulation of AFUDC until the project is resumed. For work order charges <$50K (Oklaunion-PSO, Oklaunion-TNC, & Clinch River), work orders will need to be reviewed to determine proper accounting (e.g. take no action, expense, close existing charges); work order charges >$50K will remain in construction work in progress (CWIP) or need to be reclassified depending upon the amount and projected time of suspension. Carrying charges on CWIP at Sporn U1&3 and

CAPITAL PROGRAM APPROVAL REQUISITION

Clinch River will be sought in the VA E&R proceeding. Other CWIP or reclassified amounts will be recovered through base rate proceedings in the applicable jurisdiction if the projects are completed.

Project Contacts

Contact	Name	Telephone
Project Manager	Jennifer Watters	200-1277
Requisition Detail Provider	Jennifer Watters	200-1277

Date August 7, 2013

Company	CI/LI/CPP/Program Number	Version
Indiana Michigan Power AEP Generating	RKENVCPP0	3

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	DEA 8/7/13		DEA 8/7/13

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	D. Lee	7/31/2013	
	P. Chodak	8/1/2013	
1	D. Adams	DEA 8/7/13	
2	D. Lynch	8/9/13	
3	L. L. Dieck	8/12/13	
	C. Zebula		
	B. X. Tierney		
4	M.C. McCullough		
5	R. P. Powers	RPP	
6	N. K. Akins	8/20/13	
	Buckeye Power Approval		
7	Darryl Lynch - 28th floor Ext 1142		
		8/20/2013	Approved in PeopleSoft
		August	Month Included in Board Package

Alternate CP&B Contacts:
Darryl Lynch- 28th Floor - Ext 1142

Scanned File Name: I&M RKENVCPP0 Version 3.pdf

Capital Program Approval Requisition

Company: AEP Generating Company and Indiana Michigan Power Company

Project: RKENVCPP0 - Rockport Unit 1&2 DSI and Associated Projects - Phase 3
Rockport, IN

Description: Install a Dry Sorbent Injection (DSI) system and improvements to the existing electrostatic precipitator (ESP), activated carbon injection (ACI) system, fly ash removal (FAR) system and fly ash silos. The DSI System and other improvements are designed to achieve up to 50% SO2 removal and reduce emissions of mercury, acid gases, total particulate matter and other hazardous air pollutants from Rockport Units 1&2 to comply with the Mercury and Air Toxics (MATS) regulation.

This project will be executed in three phases in accordance with the AEP Fleet Transition Plan, Project Execution Strategy.

CI Version 1 (stand-alone CI) approved testing of DSI at Rockport Unit 2 in 2011 to determine the feasibility of DSI technology to capture HCl and SO2 in conjunction with the existing ESP and ACI system. The results of the test program indicated that a DSI system utilizing sodium bicarbonate as the sorbent, in conjunction with improvements to the existing ACI system utilizing brominated powdered activated carbon (BPAC) and the existing ESP, can achieve compliance with HCl, mercury and total particulate matter emission limits established by the MATS rule and up to 50% SO2 capture.

CI Version 2 approved the completion of Phase 1 work which consisted of project planning, conceptual engineering, design and feasibility studies needed to proceed with environmental permitting and to establish overall project definition, scope and a preliminary schedule for Rockport Unit 2. During Phase 1, the Architect Engineering (A/E) and DSI equipment supplier were selected and released to proceed with engineering and design to support critical path environmental permitting and construction planning activities.

CPP Version 1 approved Phase 2 work which allowed continuation of engineering, design, permitting and procurement activities required to maintain the construction schedule needed to comply with the April 2015 MATS compliance deadline for Rockport Unit 2.

CPP Version 2 expanded the scope of the Phase 2 work to include the addition of the installation of a DSI system and improvements to the ESP, ACI, FARS and fly ash silos at both Rockport Units 1&2. During Phase 2, the Rockport site-wide Title V air permit application was submitted and detailed engineering proceeded. Major contracts were finalized with the DSI Equipment Supplier and with construction contractors for Civil Work, the Concrete DSI Silos, and General Site Services. Several long lead procurements have also been made.

Rockport Plant is 50% owned by Indiana Michigan Power Company and 50% owned by AEP Generating Company. The total estimated project cost for all phases is now $193 million, an increase from the previous version's estimate of $187 million. The increase is due to additional ESP upgrades identified since the project was originally scoped.

Reason for this Revision: This revision requests funds for Phase 3 of the project. Phase 3 activities include: completion of project management, engineering, design, procurement, fabrication and permitting activities and the initiation through completion of construction, start-up and training activities required to install a DSI system and improvements to the existing ESP, ACI system, FAR system and fly ash silos at both Rockport Units 1&2.

Authorization Amount:

Company/ Function	Previously Approved Amount	This Submission	Total Amount to be Authorized
Indiana Michigan Power Co	40,206,385	54,795,149	95,001,534
AEP Generating Co	39,146,082	58,761,129	97,907,210
Total	**$ 79,352,467**	**$ 113,556,277**	**$ 192,908,744**

Cash Flow:

	Prior Years	2013	2014	Future Years	Total
Capital	$ 7,725,786	$ 41,089,587	$ 118,705,667	$ 25,387,704	$ 192,908,744
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 7,725,786	$ 41,089,587	$ 118,705,667	$ 25,387,704	$ 192,908,744
Associated O&M	$ -	$ -	$ 725,000	$ 725,000	$ 1,450,000

Start Date: 9/1/2011 **Completion Date:** 4/16/2015 **In Service Date:** 4/16/2015

Continued on next page

Capital Program Approval Requisition

Company: AEP Generating Company and Indiana Michigan Power Company **Version:** 3

Project: **RKENVCPP0 - Rockport Unit 1&2 DSI and Associated Projects - Phase 3**
Rockport, IN

Continued from previous page

Regulatory Cost Recovery:

Indiana Michigan Power Rockport Plant - $ 95.0M (50%)

- $ 61.8M (65%) I&M-IN Clean Coal Technology Rider, biannual filings Test Year End (TYE) Dec/June, effective July/Jan beginning 6 months after construction starts
- $ 14.3M (15%) I&M-MI Base Rate Case Filing, Projected TYE TBD w/projections through TBD, effective TBD
- $ 19.0M (20%) FERC Annual Formula Rate update, TYE 12/31/15, effective 6/1/16 with 50% of CWIP recoverable during construction

Indiana cost recovery was initiated via a Certificate of Public Convenience and Necessity filing (4/1/13), which will request inclusion of the project expenditures in the Company's biannual Clean Coal Technology Rider. Per statutory requirement, expenses may not be included until the project has been under construction for 6 months.

The first phase of Michigan cost recovery will be sought in a base rate case filing and will include expenses through projected TYE. Expenses for periods beyond initial projected TYE will be recovered in subsequent base rate case filing(s).

FERC cost recovery will be accomplished through the Company's annual true-up of FERC Formula Rates (5/31).

AEP Generating Co. Rockport Plant - $ 97.9M (50%)

- AEGCo is a wholly-owned subsidiary of AEP and sells the generation output of its ownership share to AEP affiliates

Funding:

Included in IRC Presentation	Yes	Project Funded	Yes	Offset Source	NA

Requested future year funds are included in the last official Forecast.

Approved By: D. Lee/P. Chodak/R. Powers/N. Akins **Approved On:** 8/20/2013

Capital Program Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	79,352,467	-	79,352,467
This Submission	113,556,277	-	113,556,277
RKENVCPP0	**$ 192,908,744**	**$ -**	**$ 192,908,744**

2013 Direct Cost Funding			Budget Offset Source and Amount
In Forecast	$	38,612,772	*n/a*
Offset	$	-	

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	VP, Fleet Operations	Lee, D.	See attached electronic approval	7/31/2013
amt ≤ $ 10m	Opco President	Chodak, P.	See attached electronic approval	8/1/2013
amt ≤ $ 20m	EVP - Generation	McCullough, M.		
amt ≤ $ 20m	EVP & COO	Powers, R.		8/19/13
amt ≥ $ 20m	President & CEO	Akins, N.		8/20/13
CP&B Review	SVP, Corporate Planning & Budgetting	Dieck, L.		8/5/13

Project Contacts

Contact	Name	Telephone
Project Manager	Rob Bollinger	(614)716-3766
Requisition Detail Provider	Nathan Nixt	(614)716-6716

Capital Program Approval Requisition

Component CI's

CI Number	Description of Work	Previously Approved		This Submission		Total Authorized		
		Capital	Removal	Capital	Removal	Capital	Removal	Total
RK2DSIFGD	In Duct DSI FGD / ACI	40,206,385	-	54,795,149	-	95,001,534	-	95,001,534
I&M Subtotal		40,206,385	-	54,795,149	-	95,001,534	-	95,001,534
RK2DSIFGA	In Duct DSI FGD / ACI	39,146,082		58,761,129	-	97,907,210	-	97,907,210
		-	-	-	-	-	-	-
AEG Subtotal		39,146,082	-	58,761,129	-	97,907,210	-	97,907,210
Grand Total		**$ 79,352,466**	**$ -**	**$ 113,556,277**	**$ -**	**$ 192,908,744**	**$ -**	**$ 192,908,744**

Capital Program Approval Requisition

Reason for Revision

This revision requests funds for Phase 3 of the project. Phase 3 activities include: completion of project management, engineering, design, procurement and permitting activities and the initiation through completion of construction, start-up and training activities required to install a DSI system and improvements to the existing ESP, ACI system, FAR system and fly ash silos at both Rockport Units 1&2.

Construction activities are scheduled to begin upon receipt of the modified air permit which is expected to be received around September 1, 2013. Under the modified consent decree, I&M is obligated to install DSI at Rockport Units 1&2 by April 16, 2015. This revision requests the necessary funding to complete the project previously authorized under Phase 1 and Phase 2.

Justification

CPP Version 2

Indiana Michigan Power and the electric utility industry are facing new EPA air regulations. The MATS (Mercury and Air Toxics Standard) rule imposes stringent limits on emissions of hazardous air pollutants (including mercury, acid gases and total particulate matter as a surrogate for non-mercury metals) from coal and oil-fired electric generating units. In addition, I&M is subject to the mandates of a consent decree with the Department of Justice under the New Source Review provisions of the Clean Air Act. This consent decree is currently being modified. Under the modified consent decree, I&M will be obligated to install DSI at Rockport Units 1&2 by April 16, 2015.

This revision is being made to expand the scope of the project to include the addition of the installation of a DSI system and improvements to the ESP, ACI, FARS and fly ash silos at both Rockport Units 1&2. The Rockport site-wide Title V air permit application is to be submitted in February 2013. Approval of the permit is needed by September 1, 2013 to avoid construction delays and risk to the overall project cost and MATS compliance in-service deadline. This revision requests funding for continuation of engineering, design, permitting, procurement, contracting, and long lead time fabrication and preliminary construction activities.

CPP Version 1

This request converted the standalone DSI CI into a CPP that encompasses the ESP upgrades and requested funding needed to continue Phase 2A activities. The Rockport site-wide Title V air permit application was to be submitted no later than September 2012 to avoid construction delays and risk to the overall project cost and MATS compliance in-service deadline. This revision provided funding for the continuation of engineering, design, contracting and permitting work.

CI Version 2 (Standalone project)

A revision to the original CI was required to allow completion of the Phase I conceptual engineering, project planning and definition, permitting, and Certificate of Public Convenience and Necessity (CPCN) application.

Continued on next page

Capital Program Approval Requisition

Continued from previous page

Justifications Continued

Original CI Version 1

Indiana Michigan Power (I&M) and the electric utility industry as a whole, are facing proposed new EPA regulations. The Cross State Air Pollution Rule (CSAPR) will result in significant new reductions in SO_2 and NOx emissions. The Electric Generating Unit MACT (Maximum Achievable Control Technology) Rule will impose stringent limits on emissions of hazardous air pollutants, such as mercury, acid gases, and total particulate matter, from coal and oil-fired electric generating units. In addition, I&M is subject to the mandates of a consent decree executed with the Department of Justice under the New Source Review provisions of the Clean Air Act. I&M is currently obligated by the Consent Decree to install SCR and FGD systems at Rockport Unit 1 by December 31, 2017 and at Rockport Unit 2 by December 31, 2019. The CSAPR and EGU MACT proposed rules are expected to accelerate the requirement significantly.

The results from the testing program were to support air permit modeling for the site air permit modification, which will be submitted to IDEM in Q1 2012.

This CI also supported plans to prepare a Certification for Public Convenience and Need (CPCN) application in Q1 2012.

Other Alternatives Considered

- Install Dry Flue Gas Desulfurization (DFGD) system with an integrated Pulse Jet Fabric Filter
- Retire and replace generation with natural gas combined cycle
- Retire and replace generation with capacity and energy purchases from PJM

Conclusion

This revision is being made to fund Phase 3 of the project including the completion of project management, engineering, design, procurement, fabrication and permitting activities and the initiation through completion of construction, start-up and training activities required to install a DSI system and improvements to the existing ESP, ACI system, FAR system and fly ash silos at both Rockport Units 1&2. Construction activities are scheduled to begin upon receipt of the modified air permit which is expected to be received around September 1, 2013. Under the modified consent decree, I&M is obligated to install DSI at Rockport Units 1&2 by April 16, 2015. This revision requests the necessary funding to complete the project previously authorized under Phase 1 and Phase 2.

Associated Projects

- ESP and FAR system improvements
- ACI system improvements

Date June 5, 2012

Company	CI/LI/CPP/Program Number	Version
AEP Generating Company and Indiana Michigan Power	RK000LDFA and RK000LDFL	2

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	BU/OPCo has verified funding is in budget. If not in budget, funding has been identified and fund transfer has been received.	Reviewed by CP&B
	JCF 6-5-12		JCF 6-5-12

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	B. A. MacPherson		
1	D. Lynch	6/6/12	
2	L. L. Dieck	6/7/12	
	C. Zebula		
	B. X. Tierney		
	M. Heyeck		
	B. D. Radous		
	S. Burge		
	L.J. Weber		
3	M. C. McCullough	6/8/12	
	D. E. Welch		
	R. P. Powers		
	L. Barton		
	Buckeye Power Approval		
4	N. K. Akins	6/8/12	
5	Jenifer Fischer - 28th floor Ext 3032		
		6-11-12	Approved in PeopleSoft
		Jun 2012	Month Included in Board Package

Alternate CP&B Contacts:
Cathy Warchal - 28th Floor - Ext 1347

Scanned File Name: AEG and I&M RK000LDFA & RK000LDFL Version 2.pdf

Capital Improvement Approval Requisition

Company: AEP Generating Company and Indiana Michigan Power Company **Version 2**

Project : **RK000LDFA and RK000LDFL - Rockport Plant FGD Landfill - Phase 2**
Rockport, IN

Description: The Rockport Power Plant has an existing 460 acre landfill (which includes Storage Areas 1A and 1B) that is permitted to accept the plant's current Type 2 ash. Storage Area 1A is currently active.

Due to changes in air emissions regulations including the recent Cross State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) Rule, Indiana Michigan Power (I&M) will be required to install various environmental controls on both units. The resulting waste will require a Type 1 disposal facility. Area 1A of the existing landfill will be designed, re-permitted and reconstructed for Type 1 waste disposal. The project will consist of the conversion of the landfill and construction of the Leachate Collection and Management Systems. The current Type 2 cells will be placed in service, and new cells that meet Type 1 requirements will be constructed on top of the existing 1A cells.

Version 1 of the project authorized Phase 1 engineering, design and permitting. Preliminary construction of the landfill also began under Phase 1. The total cost for all phases was originally estimated at $81.6 million.

Reason for Revision: This revision requests the funds for Phase 2 of the project, which will complete the landfill conversion and allow it to accept Type 1 ash. Phase 2 will be the final phase of the project.

Rockport Plant is 50% owned by Indiana Michigan Power and 50% owned by AEP Generating Company.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
AEG	678,641	15,660,069	16,338,710
I&M	678,641	16,066,949	16,745,590
Total	**$ 1,357,282**	**$ 31,727,018**	**$ 33,084,300**

Cash Flow:

	Prior Years	2012	2013	Future Years	Total
Capital	$ 135,372	$ 4,417,892	$ 9,012,408	$ 19,518,628	$ 33,084,300
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 135,372	$ 4,417,892	$ 9,012,408	$ 19,518,628	$ 33,084,300
Associated O&M	$ -	$ -	$ -	$ -	$ -

Start Date: 6/10/2011 **Completion Date:** 12/31/2017 **In Service Date:** 12/31/2016

Continued on next page

Capital Improvement Approval Requisition

Company: AEP Generating Company and Indiana Michigan Power Company **Version 2**

Project : **RK000LDFA and RK000LDFL - Rockport Plant FGD Landfill - Phase 2**
Rockport, IN

Continued from previous page

Regulatory Cost Recovery:

AEP Generating Co. – Generation - $16.34M (50%)

- $16.34M (100%) AEGCo is a wholly-owned subsidiary of AEP and sells the generation output of its ownership share to AEP affiliates.

Indiana Michigan Power – Generation - $16.75M (50%)

- $10.88M (65%) I&M-IN Clean Coal Technology Rider, biannual filings Test Year End (TYE) Dec/June, effective July/Jan beginning 6 months after construction starts
- $2.51M (15%) I&M-MI base rate case filing, TYE 12/31/11 w/projections through 12/31/13, effective 1/1/13
- $3.35M (20%) FERC Annual Formula Rate update, TYE 12/31/16, effective 6/1/17 with 50% of CWIP recoverable during construction

Indiana cost recovery was initiated via a Certificate of Public Convenience and Necessity filing in 2011, which requested inclusion of the project expenditures in the Company's biannual Clean Coal Technology Rider. Per statutory requirement, expenses may not be included until the project has been under construction for 6 months. Joint motion for leave to submit settlement agreement was approved by Commission, authorizing I&M to defer for subsequent recovery as capital cost through its Clean Coal Technology Rider the IN jurisdictional portion of up to $10 million for Phase I activities. A revised procedural schedule was issued that was subsequently modified; hearing is currently scheduled for 8/20/12.

The Michigan cost recovery began in the 2011 base rate case filing which included forecast expenses through CY2012. Expenses for 2013 and beyond will be recovered in a subsequent base rate case filing(s).

FERC cost recovery will be accomplished through the Company's annual true-up of FERC Formula Rates (5/31).

Funding: **2012 Control Budget** *(included in IRC Presentation)* Yes **Offset Source** N/A

Requested future year funds are included in the last official Forecast.

Approved By: S. Burge/P. Chodak/M. McCullough/N. Akins **Approved On:** 06/08/2012

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	1,357,282	-	1,357,282
This Submission	31,727,018	-	31,727,018
Total	**$ 33,084,300**	**$ -**	**$ 33,084,300**

2012 Direct Cost Budget Funding			Budget Offset Source and Amount
In Budget	$	3,164,864	
Budget Offset			

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	SVP, Business Unit	Burge, S.	See electronic approval attached	5/25/2012
amt ≤ $ 10m	Opco President	Chodak, P.	See electronic approval attached	6/1/2012
amt ≤ $ 20m	EVP & COO/EVP	McCullough, M.	MC McCullough by WL Luffman	6/8/12
amt ≥ $ 20m	President & CEO	Akins, N.	Nick Akins	6/8/12
CP&B Review	Senior Vice President	Dieck, L.	L J Dieck	6/7/12

Project Contacts

Contact	Name	Telephone
Project Manager	Meghan E Roberts	8-200-3254
Requisition Detail Provider	Meghan E Roberts	8-200-3254

Capital Improvement Approval Requisition

Reason for Revision (Version 2)

The scope of this revision is to complete the activities associated with Phase II – Construction.

- Construct the cells necessary for the Type 1 Landfill in Storage Area 1A.
- Construct and place in-service the Type 1 cells.
- Construct the leachate collection system.

Version 1 Project Justification

I&M is required to comply with new EPA air regulations. The CSAPR will result in significant reductions in allowable SO_2 and NO_x emissions. The Mercury and Air Toxics Standards (MATS) Rule will impose stringent limits on emissions of hazardous air pollutants (including mercury, acid gases, and total particulate matter as a surrogate for non-mercury metals) from coal and oil-fired electric generating units. In addition, I&M is subject to the mandates of a consent decree executed with the Department of Justice under the New Source Review provisions of the Clean Air Act.

I&M's preliminary analysis of CSAPR and MATS rules indicates that, at a minimum, one unit at the Rockport Plant will be required to have Dry Sorbent Injections (DSI) FGD in-service during the second quarter of 2014. The waste generated by this process was determined to be Type I during testing in October 2011. The first cell for the Type I landfill will be in-service to accept waste from the DSI FGD.

Other Alternatives Considered

Re-design of Area 1B was considered but the permitting process would take much longer and this area is not currently in-use. Area 1A is currently in-use and development of a Type 1 landfill in this area maintains one location for landfill operations and minimizes the permitting time.

Conclusion

AEP should authorize funds to proceed with Phase 2 of the project to support the operational date of the second quarter of 2014 for the DSI FGD System.

Associated/Future Projects

RK1FGDSCR - Rockport Unit 1 SCR and FGD and Associated Work
Rockport Unit 2 DSI Retrofit Project

Linda E Jeffries /OR1/AEPIN
06/11/2012 10:39 AM

To Jenifer L Fischer/AEPIN@AEPIN
cc
bcc
Subject Fw: Signature Authority

Linda Jeffries
Administrative Assistant - Generation
(614) 716-2402 - phone
200-2402 audinet
(614) 716-1331 - fax

----- Forwarded by Linda E Jeffries/OR1/AEPIN on 06/11/2012 10:38 AM -----

Mark C McCullough /AEPIN
05/28/2012 08:19 PM

To Nicholas K Akins/AEPIN@AEPIN, Robert P Powers/BC1/AEPIN@AEPIN
cc William L Sigmon/OR3/AEPIN@AEPIN, Linda E Jeffries/OR1/AEPIN@AEPIN, tklight@aep.com@AEPIN, swburge@aep.com@AEPIN, John H Istvan/AEPIN@AEPIN, misenberg@aep.com@AEPIN
Subject Signature Authority

I will be out of the office from 5/30 - 6/21. During my absence, I am delegating my signature authority to William L. Sigmon.

Mark C. McCullough
EVP Generation
American Electric Power
614 - 716 - 2400
(audinet 200 - 2400)