STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

ILLINOIS COMMERCE COMMISSION **On Its Own Motion**	)	
	)	**Docket No. 13-0034**
Phase 2 of Approvals for the Sourcing Agreement for the FutureGen 2.0 Project	)	

SUBMISSION AND REQUEST FOR APPROVAL OF PRE-APPROVED TOTAL CAPITAL COSTS OF THE FUTUREGEN INDUSTRIAL ALLIANCE, INC.

Pursuant to the Presiding Judge's order of February 1, 2013, the FutureGen Industrial Alliance, Inc. ("FutureGen Alliance") hereby submits to the Illinois Commerce Commission ("Commission") its updated Project Cost and Ratepayer Impact Analysis ("Cost Report") with respect to the FutureGen 2.0 Project ("Project"),[1] attached as Exhibit A hereto.

In Docket No. 12-0544 ("Procurement Proceeding") the Illinois Commerce Commission ("Commission") reviewed the October 2012 Cost Report of the FutureGen Alliance, and determined that the Project Costs will be below the statutory cap.[2] The February 2013 Cost Report reflects the effect of adjusting the term of the Sourcing Agreement to 20 years as approved in the Final Order,[3] includes certain minor updates resulting from the due diligence review of Project capital costs conducted by the United States Department of Energy ("DOE"), and a small increase in the capacity of the project. The net ratepayer impact of these changes is <1% and the Project Costs continue to remain substantially below the statutory cap.

[1] The costs of the Project described in the Cost Report are hereinafter referred to as the "Project Costs."
[2] Final Order, Docket No. 12-0544, at 233 (Dec. 19, 2012).
[3] *Id.* at 232.

I. Project Background and Benefits

The Project is comprised of two related but distinct components, both of which are in the planning, permitting and design phase. The oxy-combustion power plant component involves the retrofit and repowering of a coal-fired power plant in Meredosia, Illinois with an advanced oxygen-combustion technology. This technology is designed for 98% CO_2 capture during steady-state operations, and will reduce SO_X, NO_X, mercury and particulate emissions to levels well below applicable emissions regulatory requirements. The oxy-combustion project will retrofit and repower the Meredosia plant's unit #4 steam turbine generator, using certain coal-based infrastructure associated with units #1, #2, and #3, and certain of the site's common facilities. The DOE has committed $590 million to this component of the Project.

The second component of the Project, the CO_2 pipeline and storage component, will annually accept and transport more than one million metric tons of CO_2 produced by the oxy-combustion component of the Project, and inject it for final storage in the Mount Simon deep saline geologic formation. Also included in the CO_2 storage project will be visitor, research, and training facilities. The DOE has committed $459 million to this portion of the Project. These DOE funds, in combination with additional non-federal funds, will provide 100% of the capital cost of these pipeline and storage project facilities. As a result, no pre-approved capital is requested for this component of the Project.

Taken together, the Project components will bring major benefits to Illinois, including construction job creation, permanent job creation, property tax revenue, and a new market for high-sulfur Illinois coal. These and other significant benefits are further detailed in the Cost Report.

II. Project Costs

The Project Costs contained in the Cost Report were estimated from the "ground up," using figures supplied by the FutureGen Alliance's technology partners and outside experts. The estimates include the cost of purchasing the Meredosia plant and certain related assets at the site; all engineering, procurement and construction costs; all testing, startup and commissioning costs; financial closing costs; debt service reserves; and management reserves. As further detailed in the Cost Report, the Project is being planned in such a way as to ensure as much long-term stability in Project Costs as possible, as early as possible.

The all-in capital cost of the oxy-combustion power plant component of the Project is estimated to be $[redacted] million, of which nearly half will be provided by federal funding and other cash contributions. As further detailed in the Cost Report, the FutureGen Alliance is requesting that the Commission approve the net cost, or $[redacted] million, as the Pre-approved Total Capital Costs, in this Phase 2 proceeding.

The projected rate impacts have increased modestly as compared to the Cost Report filed in the Procurement Proceeding dated October 3, 2012, owing to increased capital required because of the reduction in the term of the Sourcing Agreement from 30 years to 20 years. The FutureGen Alliance agreed to this change in the Sourcing Agreement term at the urging of ICC Staff, but clearly noted at the time that reducing the term would result in a shorter cost recovery period for the same Project Costs. *See* FutureGen Oct. 15 Response, Docket No. 12-0544, at 24-25. The shortening of the Sourcing Agreement term thus necessitates increased financing related costs, increased annual debt service and increased debt service reserves. As indicated above, a DOE due diligence review also produced modest cost increases in this Cost Report as compared to the document submitted in October. Nevertheless, the forecasted annual incremental rate impact of the Reference Case on all retail customers remains well below the statutory rate caps for each year during the 20-year term of the Sourcing Agreement. These annual impacts are presented in Figure 2 of the Cost Report. The average customer impact over the life of the Project is estimated to be 1.52 $/MWh (0.152 cents/kWh), or a 1.32% increase above the May 2009 bundled retail rates. This is well below the statutory rate cap of 2.015%.[4]

To reduce the impacts of shortening the term of the Sourcing Agreement to 20 years, the FutureGen Alliance has identified a capacity upgrade to the Project that would add approximately 8 MW to the output of the existing unit #4 steam turbine generator at the Meredosia plant. With this upgrade, the gross output of unit #4 would increase from 167.726 MW to 175.626 MW. This upgrade will decrease the unit cost of power from the Project, and have the additional benefit of not requiring any additional fuel consumption. The additional capital cost required to increase the steam turbine capacity is approximately $[redacted] million. The FutureGen Alliance requests the Commission to approve the incorporation of this upgrade into the Project and the Project Costs.

[4] *See* 20 ILCS 3855/1-75(d)(2)(E).

IV. Conclusion

Wherefore, for the foregoing reasons, the FutureGen Alliance requests that the Presiding Judge issue an order recommending the approval of the FutureGen Alliance's proposed Pre-approved Total Capital Costs, as further explained in the Cost Report attached as Exhibit A hereto.

Respectfully Submitted,

FUTUREGEN INDUSTRIAL ALLIANCE, INC.

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VERIFICATION

I, Paul Champagne, President of PKM Energy Consulting, LLC acting in the capacity as Chief Development Officer for the FutureGen Industrial Alliance, Inc., hereby state that I have read the foregoing document, and that the facts stated therein are true and correct to the best of my knowledge and belief.

Paul Champagne

Subscribed and Sworn to
Before me this 19th day of
February, 2013

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Robert W. Schaeffer, Notary Public
City of Allentown, Lehigh County
My Commission Expires July 24, 2014
Member, Pennsylvania Association of Notaries

My commission expires: 07/24/2014

EXHIBIT A

FutureGen 2.0: Oxy-combustion Power Plant Project

Pre-Approved Capital Cost Request & Updated Ratepayer Impact Analysis Report

Submitted to the Illinois Commerce Commission

February 19, 2013

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Introduction

The Illinois Power Agency Act (IPA Act) created a state agency responsible for procuring electricity for Illinois retail ratepayers. Under the IPA Act, the Illinois Power Agency (IPA) serves as a procurement agent that acquires power for two of Illinois' regulated electric utilities – Commonwealth Edison Company (ComEd) and Ameren Illinois (Ameren)[1]. The IPA primarily fulfills this procurement function via an annual Power Procurement Plan, which is implemented through an annual power procurement auction. The IPA also helps administer compliance with the IPA Act's Clean Coal Portfolio Standard for both the regulated electric utilities and Alternative Retail Electric Suppliers (ARES). The IPA Act also expressly directs the IPA, as part of the procurement planning process, to consider sourcing agreements from qualifying clean coal facilities for utilities and ARES required to comply with Section 75(d) of the IPA Act and item 5 of subsection d of Section 16-115 of the Public Utilities Act.

This Pre-Approved Capital Cost Request and Updated Ratepayer Impact Analysis report is provided to the Illinois Commerce Commission (ICC) pursuant to the ICC's Order dated December 20, 2012 approving the FutureGen Industrial Alliance, Inc's sourcing agreement and as directed by the Administrative Law Judge ("ALJ") Order dated February 1, 2013 ("Order") in this proceeding 13-0034. The Order directed the FutureGen Industrial Alliance Inc. to submit an estimate of the projects required pre-approved capital costs on or before February 19, 2013.

[1] Commonwealth Edison Company, a regulated electric delivery company, is a unit of Exelon Corporation headquartered in Chicago, Illinois. Ameren Illinois, a regulated electric and gas delivery company, is a unit of Ameren Corporation headquartered in St Louis, MO. Ameren Illinois is an affiliate company of Ameren Energy Generating Company which currently owns the Meredosia Energy Center.

1. Executive Summary

1.1. Project Overview

The FutureGen Industrial Alliance, Inc. (Alliance) is a non-profit corporation engaged by the United States Department of Energy (DOE) under a federal financial assistance award to implement the DOE's FutureGen 2.0 Program. The FutureGen 2.0 Program will develop, repower, own and operate the Meredosia Energy Center (Meredosia) and the integrated CO_2 pipeline and storage facility in Morgan County, Illinois. FutureGen 2.0 was initiated in October 2010 by DOE, which has committed more than $1 billion in American Recovery and Reinvestment Act (ARRA) funds and other appropriations for research, development and demonstration activities involving oxy-combustion and carbon dioxide (CO_2) capture, transportation, and storage. The activities are divided into two distinct, but related projects:

1) The Oxy-combustion Power Plant Project (oxy-combustion project) comprises the retrofit and repowering of a fossil fueled power plant in Meredosia, Illinois with an advanced oxygen-combustion technology. This technology is designed for 98% CO_2 capture during steady-state operations, and will reduce SO_X, NO_X, mercury and particulate emissions to levels well below applicable emissions regulatory requirements.[2] DOE has committed $590 million to this portion of the project. The Alliance has proposed to DOE that, of the $590 million, approximately $[redacted] million be committed to the over-the-fence (OTF) air separation unit (ASU). The remaining $[redacted] million will be used to directly reduce the capital cost of the remaining power plant equipment. The amount of pre-approved capital cost requested to be approved for this component of the project is $[redacted] million. The figure includes $[redacted] million for an optional steam turbine upgrade which increases plant efficiency and reduces the unit cost of electricity. The request is detailed in the balance of this report.

[2] The IPA Act requires that clean coal facilities that are assumed to commence operation during 2017 capture at least 70% of the total CO_2 emissions that the facility would otherwise emit.

2) The CO_2 Pipeline and Storage Project (CO_2 storage project) which must annually accept, transport, and store more than 1 million metric tons of CO_2 produced by the oxy-combustion project in the Mount Simon deep saline geologic formation. Also included in the CO_2 storage project will be research, training, and visitor center facilities. DOE has committed $459 million to this portion of the project. These DOE funds, plus additional Alliance contributions, will provide 100% of the capital cost of these facilities. No pre-approved capital is requested for this component of FutureGen 2.0.

The oxy-combustion project will retrofit and repower Meredosia with a near-zero emissions oxy-combustion process utilizing the unit #4 steam turbine generator, certain coal-based infrastructure associated with units #1, #2, and #3, and certain of the site's common facilities. The project will use a blend of high sulfur Illinois bituminous coal (60%) and low sulfur Powder River Basin (PRB) coal (40%) and have a gross output capacity of 176.3 MW, which includes an approximate 8 MW capacity increase that results from a steam turbine upgrade. This configuration enables the project to exceed the DOE minimum capture target requirement of 1.0 million metric tons of CO_2 per year at an 85% availability/capacity factor.[3]

As shown in Figure 1, the CO_2 storage project will transport the captured CO_2 in a newly constructed pipeline from the Meredosia site to the proposed storage facility in Morgan County, a distance of approximately 30 miles. The CO_2 storage facility is being designed and permitted to accept approximately 22 million metric tons of CO_2 over a 20-year period from the oxy-combustion project.

Both projects are currently in the planning, permitting and design phase; project construction is anticipated to begin in early 2014, with commercial operations commencing in mid-2017.

[3] The actual capture volume is estimated to be 1.08 million metric tons per year.

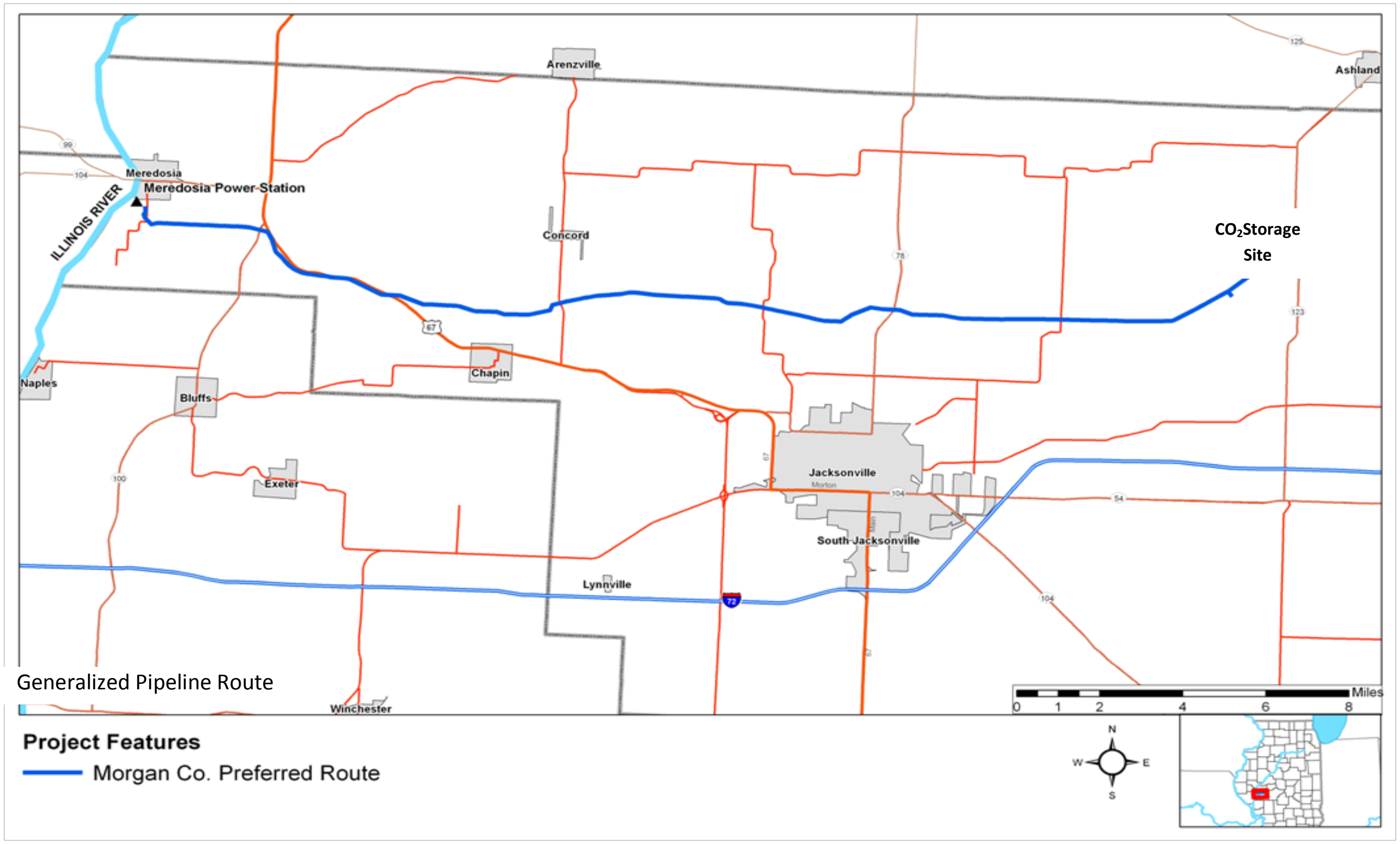

Figure 1. FutureGen 2.0 Project Map

1.2. Project Benefits

FutureGen 2.0 will provide the citizens of the State of Illinois substantial direct and indirect benefits as a result of the construction and operation of the oxy-combustion project and the accompanying CO_2 storage project. These benefits include:

- Most Cost-Effective Approach to Advance Clean Coal Technology (including carbon capture and storage) – The DOE has committed approximately $590 million of ARRA funds to help offset approximately 50 percent of the expected capital cost of the oxy-combustion portion of FutureGen 2.0. Another $459 million of DOE cost-share monies has been committed to the associated CO_2 storage project that, along with Alliance cash contributions, covers 100% of the capital cost for CO_2 storage project. The DOE cost-share monies also subsidize a portion of the projected CO_2 storage operating costs during the first four years of operation. These two subsidies make FutureGen 2.0 the most cost-effective approach to achieve progress toward Illinois' clean coal policy goals and the advancement of statutory requirements for the purchase of clean coal power.
- Low Ratepayer Impact – The proposed impact on electric customer rates is well below the statutory rate caps enacted by the Illinois General Assembly. The rate impact of FutureGen 2.0 will be competitively neutral as among all retail electricity suppliers servicing retail customers in the ComEd and Ameren services territories, and will be implemented through a tariff of ComEd and Ameren applied to all retail customers in the ComEd and Ameren service areas.[4]

[4] The ICC's Order of December 20, 2012 stated that FutureGen will contract only with ComEd and Ameren and that project costs are to be recovered through a new, or modification of an existing tariff from all retail customers through a competitively neutral charge.

- Construction Job Creation – At the peak of construction, which is scheduled to occur in 2014 through 2016, FutureGen 2.0 (the oxy-combustion project and associated CO_2 storage project) is estimated to require between 700 and 1,000 direct employees, plus drive the creation of an additional 700 to 1,000 indirect jobs.
- Permanent Job Creation – During routine operations, FutureGen 2.0 (the oxy-combustion project and associated CO_2 storage project) is expected to create approximately 100 to 125 full-time on-site jobs. In addition to the permanent jobs created, the project will generate additional employment related to the mining and transportation of the fuel to the Meredosia site and the disposal of the fly and bottom ash to an off-site facility.
- Property Tax Revenue Growth – The capital investment in Morgan County is expected to result in a three-fold increase to the existing property tax revenues generated by the Meredosia Energy Center.
- Utilization of High Sulfur Illinois Coal – The oxy-combustion project is expected to use between 300,000 and 400,000 tons per year of high sulfur Illinois bituminous coal.
- Steam Turbine Upgrade – An increase in the capacity and efficiency of the existing Meredosia Energy Center unit #4 steam turbine generator by approximately 8 MW has been identified which requires no additional fuel consumption.

1.3. Ratepayer Impact

The incremental rate impact of the oxy-combustion project is forecasted to be well below the IPA Act statutory rate caps for each year during the approved 20-year term[5] of the sourcing agreement for all retail customers in the ComEd and Ameren service areas.[6] The annual rate impacts are presented below in Figure 2. The average customer impact over the 20-year sourcing agreement term is estimated to be 1.52 $/MWh (0.152 cents/kWh) or only a 1.32% increase above the May 2009 bundled retail rates, which is well below the statutory rate cap of 2.015%. These impacts compare favorably with those submitted by the Alliance to the ICC in October 2012.[7] The rate impacts include the requested $[redacted] million of pre-approved capital costs.

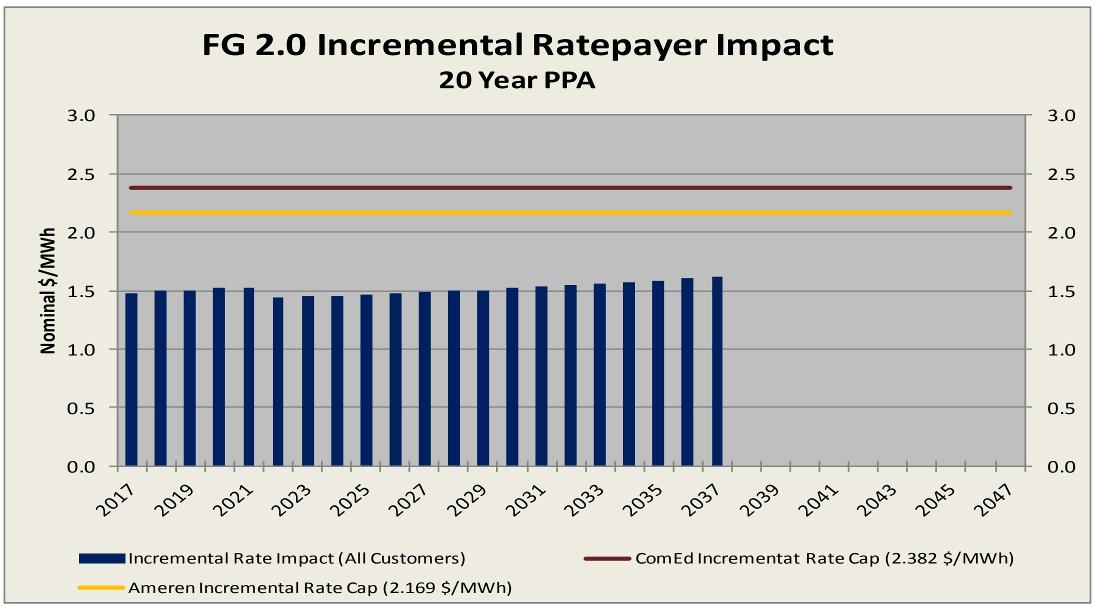

Figure 2. Reference Case Incremental Ratepayer Impact

[5]The ICC's Order of December 20, 2012 approved a 20-year term for the sourcing agreement.
[6]The IPA Act statutory rate cap is determined as 2.015% of the amount paid per kilowatt hour by eligible ComEd or Ameren customers during the year ending May 31, 2009. As defined in the previous sentence the statutory rate cap for ComEd eligible retail customers is 2.382 $/MWh and for Ameren eligible retail customers is 2.169 $/MWh.
[7] The average customer rate impact provided in the October 2012 Project Cost and Ratepayer Impact Analysis Report for the proposed 30-year term of the PPA were estimated to be 1.505 $/MWh (0.1505 cents/kWh) or only a 1.31% increase above the May 2009 bundled retail rates.

The incremental customer rate impacts shown in Figure 2 were determined by taking the difference between the annual cost-of-service and the revenues received from selling the generation output of the project into the Midwest Independent System Operator (MISO) wholesale energy market. This difference is expressed in dollars per MWh by dividing the resulting cost differential by the forecasted retail load for the ComEd and Ameren service areas. The annual cost-of-service is the sum of the capital recovery component, fuel component, fixed and variable non-fuel operating expenses including the transportation and storage of the captured CO_2, less any expected or received project revenues (i.e., installed capacity sales, ancillary services, sale of excess CO2, etc.).

Using the ICC's most recently published Comparison of Electric Sales Statistics published in June 2012, the incremental rate impacts were translated into first year and average incremental monthly bill impacts for residential and small commercial customers served by ComEd and Ameren. These monthly bill impacts are shown in Figures 3 and 4 below. For residential customers purchasing fixed price electric service from ComEd in 2011 the monthly bill impact is slightly more than $1 per month in the first year of the project. Over the 20-year term of the sourcing agreement, the forecasted average monthly bill impact is estimated to only be $1.04 per month. For residential customers purchasing fixed price electric service from Ameren in 2011, the monthly bill impact is estimated to be $1.38 per month in the first year of the project and over the 20-year term of the sourcing agreement the average monthly bill impact is expected to be only $1.42 per month. The monthly bill impact for small commercial customers purchasing fixed price service from either ComEd or Ameren in 2011 for the first year of the project have been estimated to be less than $3.50 per month and, over the 20-year sourcing agreement term, less than $4 per month.[8]

[8] The monthly bill impacts compare favorably with those presented in the October 2012 Project Cost and Ratepayer Impact Report.

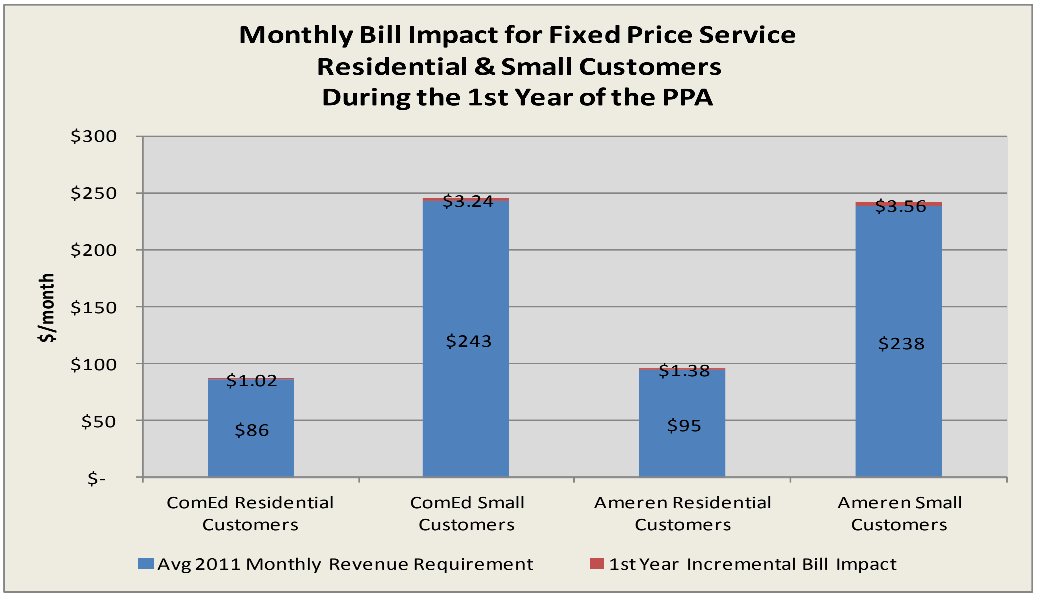

Figure 3. First Year Monthly Bill Impact

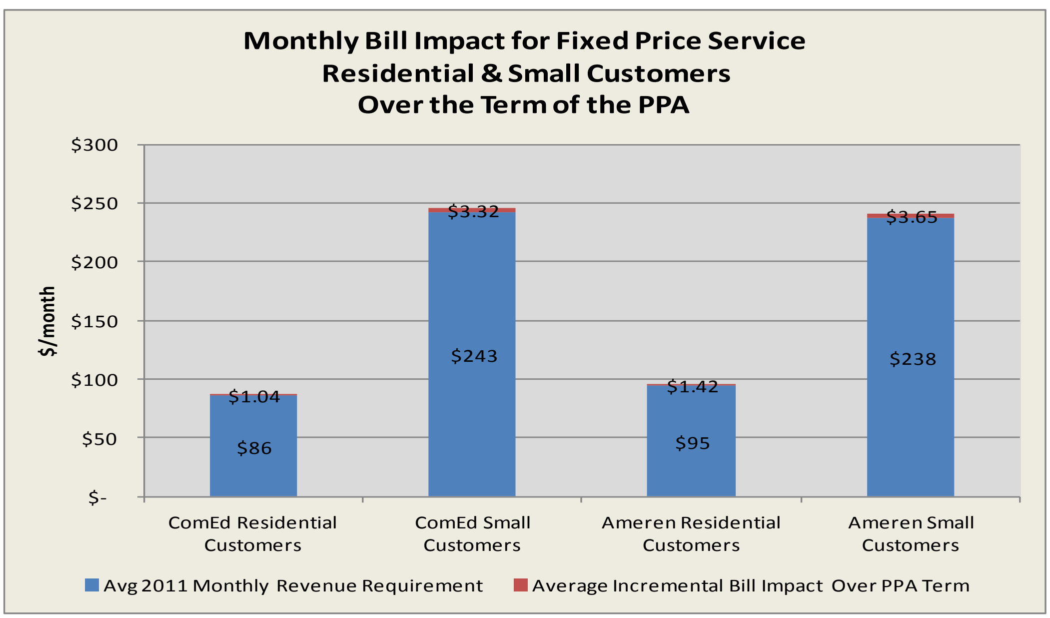

Figure 4. Average Monthly Bill Impact

1.4. Capital Cost

The total estimated "all-in" capital cost for the oxy-combustion project Reference Case with a 20-year sourcing agreement in as-spent dollars is $[redacted] million (see Table 1). The "net" capital cost for the oxy-combustion power plant after crediting to capital costs the remaining $[redacted] million in DOE funding and other non-federal cash contributions is $[redacted] million. This "net" capital cost of $[redacted] million is the amount of pre-approved capital costs that FutureGen 2.0 is requesting the ICC approve in this Phase 2 proceeding.

In October 2012, as part of the Phase 1 proceeding, the Alliance provided a Project Cost and Ratepayer Impact Analysis which included an "all-in" capital cost of $[redacted] million and a "net" capital cost of $623 million. This updated analysis (February 2013) includes a "net" capital of $[redacted] million which reflects the adjustment of the sourcing agreement term to 20 years, minor updates driven by DOE's due diligence review of capital costs, and an 8 MW capacity and efficiency upgrade of the Meredosia unit #4 steam turbine. The capital required for the steam turbine capacity upgrade is approximately $[redacted] million, which includes all design, equipment, and installation costs as well related financing charges. The remaining $[redacted] million is attributed to DOE due diligence findings and increased financing costs and debt service reserves associated with the reduction in the term of the sourcing agreement. While these updates increase the total project capital cost, the net ratepayer impact decrease by 2.5%.[9]

Table 1. Oxy-Combustion Project Capital Cost Estimate

[TABLE REDACTED]

The Reference Case oxy-combustion project cost estimate was developed from the ground up, with each supplier (The Babcock & Wilcox Company (B&W) for the boiler and gas quality control system, and Air Liquide (AL) for the ASU and Compression and Purification Unit (CPU)) providing the costs for their respective island scopes, URS for the balance of plant, and the

[9] As measured as the percentage difference from the May 2009 bundled retail rates

Alliance and URS providing the estimate of the owner's costs. This estimate includes the purchase of the Meredosia assets by the Alliance from Ameren Energy Generating Company (AEG); all engineering, procurement and construction (EPC) costs associated with the repowering; owner-related costs; performance testing, startup and commissioning costs; financial closing costs; initial working capital; debt service; and owner's management reserve.

The ASU will be partially owned by a third party and operated by that party with oxygen supplied on an OTF basis. Consequently, the all-in capital for the oxy-combustion power plant does not include the ASU capital. While the OTF approach is currently contemplated in the Reference Case economics, the Alliance and its partners are still evaluating the self-build option for the ASU. Phase I of the FutureGen 2.0 project (the Project Definition phase) was completed in late 2012 and the project started Phase II (Permitting and Design) in early February 2013. During Phase II, the Alliance and its partners envision that approximately 90% of equipment design and process and controls engineering will be completed and that significant progress will be made in establishing vendor contracts to provide pricing certainty for equipment and materials. This is a far greater level of design and cost certainty than is typical for most coal-fueled power plant projects.

As important, the Alliance will be entering into fixed price EPC agreements with B&W and AL for their respective portions of the project. The Alliance, B&W, and AL also intend to have a contractual relationship for the start-up, commissioning, and performance testing of the repowered facility (Phase III). By completing this level of engineering, design and procurement readiness and by using this contracting approach, the Alliance will be able to achieve greater certainty about the project's cost and schedule before financial close and the start of construction in Phase III as compared to a typical coal-fuel power plant.

1.5. Cost of Power

Based on the capital cost estimate discussed above and the operating cost assumptions provided in this section, the 20-year levelized cost of electricity (LCOE) for the oxy-combustion project, expressed in 2012 dollars, is forecasted to be $131.3/MWh assuming a 10% discount rate and $144.6/MWh assuming an 8% discount rate (see Figure 5). The LCOE includes the expected capital recovery component, fuel charges, plus non-fuel fixed and variable operating expenses including all CO_2 capture and storage costs components that are part of the sourcing agreement formula rate. The updated LCOE is approximately 2.5% less than the LCOE provided in the October 2012 report. In addition, FutureGen's LCOE is still approximately 15% to 30% lower than that reported for the Initial Clean Coal Facility,[10] while having the benefit of a CO_2 capture rate that is approximately 30% greater.

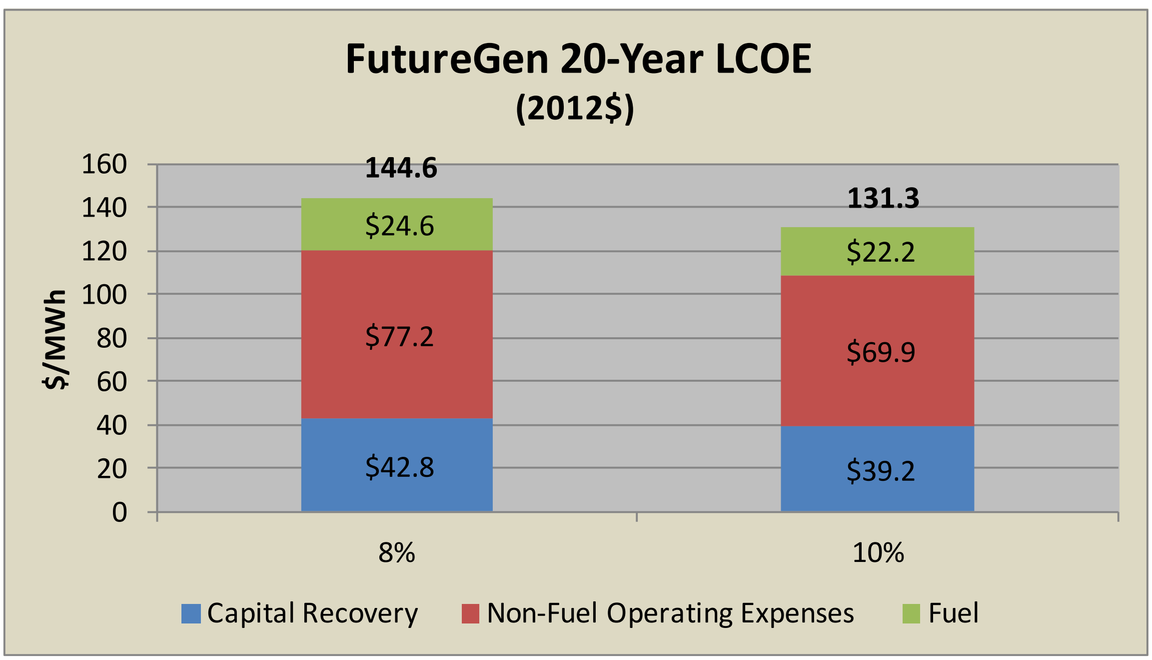

Figure 5. Reference Case 20-Year LCOE

[10] Source: *Facility Cost Report,* February 26, 2012, p.12. FutureGen 2.0 LCOE in 2010$ ranges from $109 /MWh to $124/MWh as compared to the Initial Clean Coal Facility's cited LCOE in 2010$ of $150/MWh.

The forecasted annual cost of power based on the 20-year contract term and formula rate cost components described in the sourcing agreement are summarized in Figure 6 and Table 2.

Figure 6. Cost of Electricity

[FIGURE REDACTED]

Table 2. Cost of Electricity – 20-Year PPA

[TABLE REDACTED]

2. Oxy-Combustion Power Plant Project

2.1. Introduction

The oxy-combustion project will retrofit and repower the Meredosia Energy Center with a near-zero emissions oxy-combustion process utilizing the unit #4 steam turbine generator while also using coal-based infrastructure from units #1, #2, and #3 and certain of the site's common facilities. Oxy-combustion is the combustion of coal with nearly pure oxygen and recycled flue gas (instead of air), resulting in a flue gas byproduct that is primarily CO_2 instead of nitrogen. This facilitates the capture of the CO_2 so that it can be readily sequestered. See Figure 7.

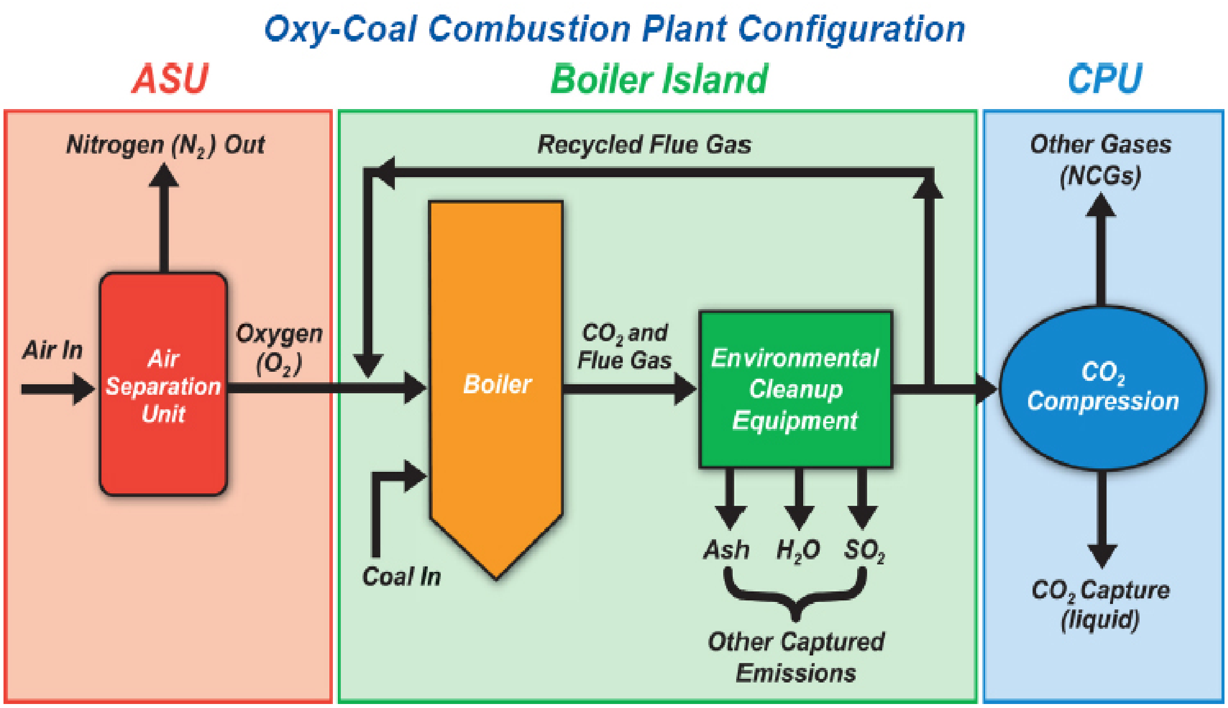

Figure 7. Oxy-Coal Combustion Plant Configuration

The project is divided into separate islands, with island scope of responsibility as follows:

- Boiler, Gas Quality Control System (GQCS) and Balance of Plant (BOP) – B&W
- ASU – AL
- CPU – AL

The plant capacity and configuration have been developed using B&W's cool recycle oxy-combustion process firing a mix of high sulfur Illinois bituminous (60%) and low sulfur PRB coal (40%). The use of this technology allows for 98% of the flue gas CO_2 being captured for transport and storage. This result exceeds the DOE minimum 90% capture design requirement. The October 2012 design was focused on baseload operation with the gross capacity established at 168.4 MW, which enables the project to capture 1.1 million metric tons per year, which exceeds the minimum DOE capture requirement of 1.0 million metric tons per year at an 85% capacity factor. The upgrade to the unit #4 steam turbine does not impact the estimated CO_2 capture rate.

2.2 Capital Cost

The total estimated "all-in" capital cost for the oxy-combustion project in as-spent dollars is $[redacted] million as summarized in Table 4. The project cost estimate was developed from the ground up, with each island supplier providing the costs for their respective island scope, and with the Alliance and URS providing the owner's cost estimate

This estimate includes the purchase of Meredosia assets and associated permits, all EPC costs associated with the repowering, owner's costs, startup, commissioning costs, financial closing costs, initial working capital, debt service and owner's management reserves.

One important aspect of the capital cost analysis is that the project is being undertaken by the Alliance, B&W, AL and DOE using a phase gate approach. The project is currently planned in four phases:

- Phase I – Project Definition and Pre-Front-End Engineering Design (Pre-FEED)
- Phase II – National Environmental Policy Act (NEPA), Permitting and Final Design
- Phase III – Construction and Commissioning
- Phase IV – Operations

By using this phased approach the Alliance and its partners will be able to achieve much greater cost and schedule certainty before starting construction.

Phase I has been completed and the Alliance initiated Phase II in early February 2013. During Phase II, the Alliance and its partners envision that approximately 90% of equipment design and process and controls engineering will be completed and that significant progress will be made in establishing vendor contracts to provide pricing for long lead equipment and, materials. This is a far greater level of design and cost certainty than is typical for most coal-fueled power plant projects.

As important, the Alliance will be entering into fixed price EPC agreements with B&W and AL for their respective portions of the project. The Alliance, B&W, and AL also intend to have a contractual relationship for the start-up, commissioning, and performance testing of the repowered facility. By completing this level of engineering, design and procurement readiness and by using this contracting approach, the Alliance will be able to achieve greater certainty about the project's cost and schedule before financial close and the start of construction.

Table 3. Oxy-combustion Project Reference Case Capital Cost Estimate Summary

[TABLE REDACTED]

The estimate follows the recommended practices (18R-97) for classification as set forth by AACE International. The practice establishes minimum boundaries around the level of effort required to produce a certain level of accuracy estimate. Key documents such as PFDs and P&IDs are important deliverables in determining the level of project definition, and thus the level of accuracy associated with the estimate effort.

The approximately 8 MW increase in unit #4 steam turbine capacity would be accomplished by replacing the existing high, intermediate and low pressure steam turbine blades and ancillary equipment with higher efficiency turbine blades. With this upgrade the expected gross output of unit #4 would increase from 167.726 MW to 175.626 MW. The additional capital cost required for this upgrade is approximately $[redacted] million, which includes the design, engineering, equipment, installation and related financing charges and is included in the "all-in" capital cost for project summarized in Table 3.

The ASU is not included in the capital cost estimate, but rather is assumed to be owned and operated by AL with the required oxygen for the project being supplied on an over-the-fence basis (OTF). While the OTF approach is currently contemplated in the Reference Case economics, the Alliance and its partners are still evaluating the self-build option for the ASU. The specific estimating methods used varied between the islands, based on each participant's standard work processes, but generally encompassed the following.

- Preliminary equipment designs were prepared based on the Design Basis Document and other key process information. In the majority of cases equipment was quoted by Vendors normally utilized by each island supplier in response to extensive technical/commercial request for bid packages. These quotes were validated against recent purchase information and tuned to reflect the best estimate of final price paid in a "real purchase" scenario.
- Where vendor quotes were not obtained, costs were estimated based on experience and internal cost database information.
- Material take offs (MTO's) for many bulk items, including site preparation, piping, electrical, structural steel (pipe racks) and concrete foundation work, were prepared for the initial Phase I design, and then factored to account for later Phase I design changes.
- In many cases, local area contractors who have serviced AEG on recent large projects were used to independently develop estimates as validation.
- For those items not covered by vendor quoted subcontracts, engineering and installation labor was estimated based on the division of responsibility, MTO's, and schedule using in-house information for each island supplier.
- Illinois craft labor rates were based on labor survey information gathered from the local union halls. The basis for the estimates assumes a project labor agreement (or comparable legal agreement is in place).
- Island-specific EPC management reserve was included based on a Monte Carlo analysis, with inputs from each participant for their respective cost items.

The $[redacted] million in Owner's Costs developed by the Alliance and URS are summarized in Table 4. These costs were prepared based on inputs derived from overall project schedule, the Pre-FEED Design and Cost Basis outputs, advice from the Alliance's financial advisor, expected operating costs and previous project experience. The increase in Owner's Costs as compared to the estimate provided in October 2012 can be attributed to DOE due diligence findings, increased financing costs and debt service reserves because of the reduction in the term of the sourcing agreement, and a slight increase owner's management reserves[10]

Table 4. Owner's Cost Estimate Summary

[TABLE REDACTED]

2.3. Facility Performance

Based on annual average baseload operating conditions, including estimated equipment degradation for existing plant equipment, and the approximate 8 MW steam turbine upgrade the overall oxy-combustion plant performance is summarized in Table 5. The overall performance is as should be expected for this first-of-a-kind oxy-combustion plant repowering the older and relatively small subcritical steam cycle at Meredosia. The current predicted efficiency for the oxy-combustion project is 38.3% on a gross basis. The plant efficiency is expected to improve slightly in Phase II with further design refinements.

The cost of electricity assumes that 175,626 MW of gross generation is to be sold into the MISO wholesale power markets. The total plant auxiliary power requirements are assumed to be purchased from a retail energy supplier. This arrangement provides a lower overall cost of electricity to the ratepayer.

Table 5. Overall Plant Thermal Performance Summary

	Oct 2012 Report	**Feb 2013 Report**
Steam Turbine Generator Output (gross)	168,400 kW	176,300 kW
Generator Step-Up Transformer Losses	674 kW	674 kW
Steam Turbine Gross Generation to 138 kV Grid	167,726 kW	175,626 kW
Gross Plant Heat Rate, HHV	9,321 Btu/kWh	8,903 Btu/kWh
Gross Plant Efficiency, HHV	36.7%	38.3%
Total Plant Auxiliary Power	68,721 kW	68,721 kW
Net Plant Net Output	99,005 kW	106,905 kW

[10] Owner's management reserves are determined as a fixed percentage of expected EPC costs and certain development, permitting, start-up and commissioning and other direct costs.

Net Plant Heat Rate, HHV	15,854 Btu/kWh	14,682 Btu/kWh

2.4. Air Emissions

Resulting air emissions for this near-zero emissions plant, as well as CO_2 production criteria, are summarized in Table 6. As shown, emissions of criteria pollutants, including CO, NOx, SOx, mercury, and particulate, are expected to be very low.

Table 6. Oxy-combustion Project Air Emissions and CO_2 Production Summary

Emissions	lb/hr	lb/MM Btu, HHV	CO_2 Production	
CO	4.8	0.0031	CO_2 Recovery	98% (by mass)
NO_x	≤ 35.4	≤ 0.023	Mass flow	319,000 lbs/hr
VOM	≤5.7	≤ 0.0036		
PM (Total)	Negligible	Negligible	Pressure	2,100 psig
SO_2	≤ 0.02	≤ 0.000013	Temperature	71 °F
Hg	Negligible	Negligible	CO_2 purity	99.8% (by mass, dry)

Emissions listed are not-to-exceed estimates based on operating conditions listed above.

The project is anticipated to perform better than current regulatory requirements. Information continues to be developed to complete the project permitting activities. To date, the initial air permit application has been submitted, the initial NPDES and state wastewater construction permits have been submitted, and the information necessary for DOE's environmental impact statement (prepared pursuant to the National Environmental Policy Act) has been completed.

2.5. Transmission Interconnection

The oxy-combustion project will electrically interconnect with the MISO network at 138 kV through an existing substation located at the Meredosia Energy Center. The project applied for network service under the MISO tariff in January 2012. MISO's Feasibility Study results showed the no network upgrades are required at this time. The project is currently participating in the next phase of MISO's interconnection study requirements which started in January 2013.

2.6. Operating Costs

The estimated fixed and variable non-fuel operating cost components of the proposed formula rate were prepared by the Alliance in consultation with AEG, B&W and their operating affiliate Delta Power Services (Delta), AL, and URS. The combined team drew on numerous years of plant operating experience and utilized information from similar projects to develop the initial operations and maintenance (O&M) staffing plans and non-fuel budgets for the project. The non-fuel fixed and variable operating costs for the Reference Case cost of electricity are presented in Table 7 and reflect minor updates since the October 2012 report.

The estimating methodology used for developing this operating and maintenance costs were the following:

- O&M costs were estimated in current year dollars and escalated on an annual basis over the 20-year term of the sourcing agreement
- Staffing levels and costs were developed based on historical operations at Meredosia and data from the operation of facilities with similar systems and equipment. The O&M organization is expected to consist of approximately [redacted] permanent staff, including [redacted] for the operation of the ASU and CPU. Salary levels were based on existing Ameren wage scales for managerial and bargaining unit employees.
- The staffing level and overall staffing costs for the boiler island, GQCS, steam turbine and BOP were reviewed by B&W's operations affiliate Delta Power Services (Delta) and found to be consistent with other facilities of this size and complexity that Delta either operates or has proposed to operate. Because the project will be operated by a contract operator such as Delta, an operator fee has been included in the budget
- Annual routine maintenance costs for the boiler island, GQCS, steam turbine and BOP systems were based on industry norms for a plant of this size and complexity. This level of expenditure was reviewed by B&W's operating affiliate and found to be consistent with other facilities of this size and complexity that Delta either operates or has proposed to operate

- Consumables, other than fuel and fuel related materials, include water treatment chemicals, reagents, and lubricants were budgeted based on expected consumption rates.

- Delivered fuel related raw material costs (lime and trona) were estimated based on information prepared by John T. Boyd Company

- Ash disposal was assumed to be offsite. Unit costs were based on a budgetary quote obtained from Area Disposal Company (ADC) of Peoria, Illinois for transporting and storing the project's fly and bottom ash at ADC's Pike County, Illinois landfill

- Annual CO_2 transportation and storage charges were based on the Alliance's Phase II application operations estimate for the Morgan County, Illinois pipeline and storage field (see Section 3)

- MISO charges for the sale of electricity into the grid were based on its Federal Energy Regulatory Commission-approved tariff rates

- Annual permit fees were based on Illinois Environmental Protection Agency regulations for air and National Pollution Discharge Elimination System requirements to maintain these permits

- Insurance costs during the operating period were based on a preliminary quote from the Alliance's insurance consultant McGriff Seibels & Williams

- Purchased power costs for the projects total auxiliary loads of 68.7 MW (inclusive of the ASU) based on Ameren' distribution tariff rates, MISO transmission tariff rates and a forecast of wholesale on-peak and off-peak electricity prices at the Indiana Hub

- Financing related costs during the operating period included an estimate of the cost of the bank's administrative agent, ongoing oversight by the bank's engineer and a commitment fees on the outstanding balance of the loan

As discussed previously, the Alliance has assumed that the supply of oxygen from the ASU would be provided by AL on an OTF contract basis. In this approach AL would construct, own and operate the ASU and the project would pay a fixed facility charge plus fixed and variable operating, and power costs for the supply of oxygen. AL provided the Alliance with budgetary estimates for the annual fixed facility charge and the fixed and variable operating and maintenance charges for the ASU. The power required to run the ASU is accounted for in the projects total auxiliary power requirements.

In addition, the ASU and CPU are assumed to be operated and staffed by AL under a separate contract to the project operator. The estimated staffing level (20) and wage scale for the ongoing operation of the ASU and CPU have been included in the projects operating costs.

G&A rates of [redacted] percent and [redacted] percent of total O&M for the third-party operator and the Alliance, respectively, have also been included in the annual operating budget.
The resulting third-party operator G&A costs was reviewed by Delta and found to be within industry norms.

Table 7. Total Non-Fuel Fixed and Variable Operating & Maintenance Costs

[TABLE REDACTED]

3. CO_2 Pipeline and Storage Project

3.1 Introduction

The Alliance will site, design, obtain required permits and regulatory approvals, procure material and equipment, construct, and operate a CO_2 pipeline and storage project that is integrated in terms of technical scope, cost, and schedule with the oxy-combustion project. The Alliance is designing a CO_2 pipeline from Meredosia, Illinois to a site in eastern Morgan County, Illinois. The CO_2 pipeline and storage project is being designed to accept up to 1.1 million metric tons of CO_2 captured from the oxy-combustion project and transport it to the storage site for injection into the Mount Simon deep saline geologic formation where it will be permanently stored. The Alliance will also build visitor, research, and training facilities.

3.2. Capital Cost

The total as-spent project capital cost is estimated to be $[redacted] million. The estimate includes all direct and indirect design engineering and construction costs, development costs, general and administrative (G&A) charges, fees, and contingencies. The total capital cost also includes owner's management reserve, working capital, and CO_2 liability coverage. As discussed previously, this capital requirement will be fully funded by a combination of DOE and Alliance raised monies. No third-party equity or debt is expected to be required to complete the CO_2 pipeline and storage project. This approach to funding this portion of the project allows the Alliance to pass these savings on to ratepayers.

3.3. Operating Cost

The operation and maintenance costs for the CO_2 pipeline and storage facility were developed by incorporating cost estimates supplied by Gulf Interstate Engineering, Patrick Engineering and Battelle, plus costs for such items as property taxes, insurance, ongoing permitting and legal support, pore space royalties, G&A, and the CO_2 storage trust fund annual payments. The trust fund is required to meet federal and state regulatory requirements. In the first four years of operation, the CO_2 storage project operating costs are partially offset by DOE funds remaining following the completion of construction. It is estimated that approximately $[redacted] million of the DOE provided monies will be available to reduce operating expenses in the early years of operations. A summary of these costs is provided in Table 8.

Table 8. CO_2 Pipeline and Storage Project O&M Estimate ($000s)

[TABLE REDACTED]

4. Delivered Fuel Cost

John T. Boyd Company (Boyd) was retained by the Alliance to provide a preliminary fuel plan and 30-year price forecast for the project. As configured, the project is expected to consume approximately 600,000 tons of coal annually assuming a blend of 60% high sulfur Illinois bituminous coal and 40% low sulfur PRB coal at an 85% availability/capacity factor.

Coal prices were expressed in constant 2012 dollars freight-on-board (FOB) mine and reflect not only the affects of low natural gas prices and lower electricity demand, but more restrictive environmental regulations. The forecast assumes that prices will rise gradually in real terms because of increased production costs and lower productivity improvements. Boyd also assumed moderate economic growth through 2015.

Because no rail unloading facilities exist at the Meredosia plant, the primary sources of Illinois coal were from three mines, listed below, ranging between 50 to 75 miles from the project site. Coal from these mines can economically be delivered via truck to the plant.

Mine	Company	County	Heat Content (Btu/lb)
Viper	Arch Coal	Sangamon	10,488
Shay#1	Coalfield Transport	Macoupin	10,564
Crown III	Tri County Coal	Macoupin	11,124

Mines greater than 75 miles from the Meredosia site would require both truck and barge transportation increasing the delivered cost fuel for the project.

PRB coal was assumed to be sourced from mines located in the southern portion of the basin because of higher thermal content (8,800 Btu/lb) and lower transportation costs. These mines include the North Antelope/Rochelle mine operated by Peabody Energy, the Antelope Mine operated by Cloud Peak Energy Resources, LLC, and the Black Thunder mine operated by Arch Coal. Transportation from the PRB would consist of rail transport from the basin to Sauget, Illinois (Cahokia Dock) barge loading facility and then barge transport up the Illinois River to the Meredosia unloading facility. Transportation costs, expressed in constant 2012 dollars, were estimated for all modes of delivery rail, barge and truck from the mine to the project site.

The forecasted delivered prices of Illinois and PRB coals to the project site are summarized in Table 9 through Table 12 below. The delivered prices also reflect all state and local taxes.

Table 9. Illinois Coal Delivered Price Forecast ($2012/MMBtu)

[TABLE REDACTED]

Table 10. Illinois Coal Delivered Price Forecast (Nominal $/MMBtu)

[TABLE REDACTED]

Table 11. PRB Coal Delivered Price Forecast ($2012/MMBtu)

[TABLE REDACTED]

Table 12. PRB Coal Delivered Price Forecast (Nominal $/MMBtu)

[TABLE REDACTED]

5. Load Forecast

The estimated retail customer load forecasts used to estimate the ratepayer impacts for ComEd and Ameren were developed from information provided in the IPA's 2012 Power Procurement Plan and the company's 2011 Electric Switching Statistics filed with the ICC on January 25, 2012.

As presented in Table13, the overall load for all customer classes in the ComEd service area has been forecasted to grow at a compound annual rate of 0.54% from a base of 92,516 GWh in 2017 to 108,720 GWh by 2047.

The projected total load for residential and small commercial customers used as a starting point load data for the period 2012 through 2017 provided in the IPA's 2012 Power Procurement Plan. Beyond 2017, the load for these customer classes was forecasted to grow at compound annual growth rates of 0.64% and 0.44% respectively. These growth rates were derived from the load data provide in Table II-7 of ComEd's Load Forecast for the Five Year Planning Period June 2012 through May 2017 dated July 15, 2011, which was provided as Attachment B to the IPA's 2012 Power Procurement Plan.

The forecasted load for large/other customers during the same period was derived from the sum of the reported monthly kWh usage data for these customers reported in the 2011 Electric Switching Statistics. Since no projected growth rate for these customers was reported by the IPA or ICC, the Alliance conservatively estimated that the load for these customers would grow at the average of the growth rates for the residential and small commercial customer segments. This approach resulted in a compound annual growth rate of 0.54% for the large/other customer segment.

As presented in Table 14, the overall load for all customer classes in the Ameren service area has been forecasted to grow at a compound annual rate of 0.25% from a base of 37,645 GWh in 2017 to 40,581 GWh by 2047.

Table 13. Estimated ComEd Service Territory Retail Customer Load Forecast

		GWh				Percent Growth			
Calendar Year	Contract Year	Residential	Small C&I	Industrial/Other	Total	Residential	Small C&I	Industrial/Other	Total
2011									
2012		28,260	32,789						
2013		28,429	32,979			0.60%	0.58%		
2014		28,707	33,284			0.98%	0.92%		
2015		28,901	33,485			0.68%	0.60%		
2016		29,221	33,704			1.11%	0.65%		
2017	1	29,369	33,674	29,473	92,516	0.51%	-0.09%		
2018	2	29,558	33,824	29,631	93,013	0.64%	0.44%	0.54%	0.54%
2019	3	29,748	33,974	29,791	93,513	0.64%	0.44%	0.54%	0.54%
2020	4	29,940	34,125	29,951	94,016	0.64%	0.44%	0.54%	0.54%
2021	5	30,132	34,277	30,112	94,522	0.64%	0.44%	0.54%	0.54%
2022	6	30,326	34,430	30,274	95,030	0.64%	0.44%	0.54%	0.54%
2023	7	30,522	34,583	30,437	95,541	0.64%	0.44%	0.54%	0.54%
2024	8	30,718	34,737	30,601	96,055	0.64%	0.44%	0.54%	0.54%
2025	9	30,916	34,891	30,765	96,572	0.64%	0.44%	0.54%	0.54%
2026	10	31,115	35,046	30,931	97,092	0.64%	0.44%	0.54%	0.54%
2027	11	31,315	35,202	31,097	97,615	0.64%	0.44%	0.54%	0.54%
2028	12	31,516	35,359	31,265	98,140	0.64%	0.44%	0.54%	0.54%
2029	13	31,719	35,516	31,433	98,669	0.64%	0.44%	0.54%	0.54%
2030	14	31,923	35,674	31,602	99,200	0.64%	0.44%	0.54%	0.54%
2031	15	32,129	35,833	31,773	99,735	0.64%	0.44%	0.54%	0.54%
2032	16	32,336	35,992	31,944	100,272	0.64%	0.44%	0.54%	0.54%
2033	17	32,544	36,153	32,116	100,812	0.64%	0.44%	0.54%	0.54%
2034	18	32,753	36,313	32,289	101,356	0.64%	0.44%	0.54%	0.54%
2035	19	32,964	36,475	32,463	101,902	0.64%	0.44%	0.54%	0.54%
2036	20	33,176	36,637	32,638	102,452	0.64%	0.44%	0.54%	0.54%
2037	21	33,390	36,800	32,814	103,004	0.64%	0.44%	0.54%	0.54%
2038	22	33,605	36,964	32,991	103,560	0.64%	0.44%	0.54%	0.54%
2039	23	33,821	37,128	33,169	104,118	0.64%	0.44%	0.54%	0.54%
2040	24	34,039	37,293	33,348	104,680	0.64%	0.44%	0.54%	0.54%
2041	25	34,258	37,459	33,528	105,245	0.64%	0.44%	0.54%	0.54%
2042	26	34,478	37,626	33,709	105,813	0.64%	0.44%	0.54%	0.54%
2043	27	34,700	37,793	33,891	106,385	0.64%	0.44%	0.54%	0.54%
2044	28	34,923	37,962	34,074	106,959	0.64%	0.44%	0.54%	0.54%
2045	29	35,148	38,130	34,258	107,537	0.64%	0.44%	0.54%	0.54%
2046	30	35,374	38,300	34,443	108,118	0.64%	0.44%	0.54%	0.54%
2047	31	35,602	38,470	34,629	108,702	0.64%	0.44%	0.54%	0.54%

Sources:

1 Illinois Power Agency 2012 Procurement Plan

2 2011 Electric Switching Statistics filed with the Illinois Commerce Commission on January 25, 2012.

Table 14. Estimated Ameren Service Territory Retail Customer Load Forecast

		GWh				Percent Growth			
Calendar Year	Contract Year	Residential	Small C&I	Industrial/Other	Total	Residential	Small C&I	Industrial/Other	Total
2011		11,810	7,494	17,873	37,177				
2012		11,810	7,494	17,873	37,177	0.00%	0.00%	0.00%	0.00%
2013		11,842	7,511	17,918	37,270	0.27%	0.22%	0.25%	0.25%
2014		11,873	7,527	17,963	37,363	0.27%	0.22%	0.25%	0.25%
2015		11,906	7,544	18,008	37,457	0.27%	0.22%	0.25%	0.25%
2016		11,938	7,560	18,053	37,551	0.27%	0.22%	0.25%	0.25%
2017	1	11,970	7,577	18,098	37,645	0.27%	0.22%	0.25%	0.25%
2018	2	12,002	7,594	18,143	37,739	0.27%	0.22%	0.25%	0.25%
2019	3	12,035	7,610	18,189	37,834	0.27%	0.22%	0.25%	0.25%
2020	4	12,067	7,627	18,234	37,929	0.27%	0.22%	0.25%	0.25%
2021	5	12,100	7,644	18,280	38,024	0.27%	0.22%	0.25%	0.25%
2022	6	12,132	7,661	18,326	38,119	0.27%	0.22%	0.25%	0.25%
2023	7	12,165	7,678	18,372	38,214	0.27%	0.22%	0.25%	0.25%
2024	8	12,198	7,694	18,418	38,310	0.27%	0.22%	0.25%	0.25%
2025	9	12,231	7,711	18,464	38,406	0.27%	0.22%	0.25%	0.25%
2026	10	12,264	7,728	18,510	38,503	0.27%	0.22%	0.25%	0.25%
2027	11	12,297	7,745	18,557	38,599	0.27%	0.22%	0.25%	0.25%
2028	12	12,330	7,762	18,603	38,696	0.27%	0.22%	0.25%	0.25%
2029	13	12,364	7,779	18,650	38,793	0.27%	0.22%	0.25%	0.25%
2030	14	12,397	7,797	18,697	38,890	0.27%	0.22%	0.25%	0.25%
2031	15	12,430	7,814	18,743	38,988	0.27%	0.22%	0.25%	0.25%
2032	16	12,464	7,831	18,790	39,085	0.27%	0.22%	0.25%	0.25%
2033	17	12,498	7,848	18,838	39,183	0.27%	0.22%	0.25%	0.25%
2034	18	12,531	7,865	18,885	39,282	0.27%	0.22%	0.25%	0.25%
2035	19	12,565	7,883	18,932	39,380	0.27%	0.22%	0.25%	0.25%
2036	20	12,599	7,900	18,980	39,479	0.27%	0.22%	0.25%	0.25%
2037	21	12,633	7,917	19,027	39,578	0.27%	0.22%	0.25%	0.25%
2038	22	12,667	7,935	19,075	39,677	0.27%	0.22%	0.25%	0.25%
2039	23	12,701	7,952	19,123	39,776	0.27%	0.22%	0.25%	0.25%
2040	24	12,736	7,970	19,171	39,876	0.27%	0.22%	0.25%	0.25%
2041	25	12,770	7,987	19,219	39,976	0.27%	0.22%	0.25%	0.25%
2042	26	12,805	8,005	19,267	40,076	0.27%	0.22%	0.25%	0.25%
2043	27	12,839	8,023	19,315	40,177	0.27%	0.22%	0.25%	0.25%
2044	28	12,874	8,040	19,364	40,278	0.27%	0.22%	0.25%	0.25%
2045	29	12,909	8,058	19,412	40,379	0.27%	0.22%	0.25%	0.25%
2046	30	12,943	8,076	19,461	40,480	0.27%	0.22%	0.25%	0.25%
2047	31	12,978	8,093	19,510	40,581	0.27%	0.22%	0.25%	0.25%

Sources:

1 Illinois Power Agency 2012 Procurement Plan

2 2011 Electric Switching Statistics filed with the Illinois Commerce Commission on January 25, 2012.

Since no forecast of Ameren' total projected load for residential and commercial customers was available to the Alliance, the Alliance used the monthly kWh usage data for these customer segments reported in the 2011 Electric Switching Statistic as the starting point for the forecast. Ameren did publicly release compound annual growth rates for these customer classes during the period 2012 through 2017 in the IPA's procurement plan. The reported compound annual growth rates for the residential and commercial customers were 0.27% and 0.22%, respectively.

The starting point for the large/other customers was also derived from the reported monthly kWh usage data for these customers in the 2011 Electric Switching Statistics. Since no projected growth rate for these customers was reported by the IPA or ICC, it is assumed that the load for these customers would grow at the average of the growth rates for the residential and small commercial customer segments. This approach resulted in a compound annual growth rate of 0.25% for the large/other customer segment.

6 Level Annual Fixed Payment

As presented in Section 2.2, the total capital cost for the oxy-combustion project, in as-spent dollars, is forecasted to be $[redacted] million. The Alliance intends to finance the project with a combination of federal ARRA funding provided by DOE, non-recourse project debt, third-party equity and other cash contributions (that do not earn a rate of return). The largest source of funding is the approximately $590 million in capital originating from ARRA funding provided by DOE. The Alliance has proposed to DOE that, of the $590 million, approximately $[redacted] million be committed to the OTF ASU. The $[redacted] million buy-down in ASU capital costs directly reduces project operating costs by reducing substantially the ASU fixed facility charge that is built into the operating cost for the oxygen produced by the ASU. The ARRA monies have been contractually obligated by DOE to the project subject to phase gate approvals at the start of each DOE contract phase. Per federal statute all of the available ARRA funds must be expended prior to September 30, 2015.

The remaining $[redacted] million in federal ARRA funding will be used to directly reduce the $[redacted] million total project capital cost. The net capital cost of $[redacted] million will be funded by third party debt and equity. To the extent that other non-federal financing is raised (either derived from Alliance member contributions or domestic or foreign grants), these monies will substitute for the debt and equity, will receive no financial return, and will not result in debt carrying charges.

Based on the 55% to 45% debt equity structure and the 10% return on equity, approved during the Phase 1 proceeding, the level fixed payment for the project can be determined. For the 20-year term sourcing agreement a levelized fixed charge rate was based on the values provided in Table 16, including the approved 10% return on equity, a cost of long-term debt of approximately 7%, 20-year straight line book depreciation, 20-year tax depreciation using the Modified Accelerated Cost Recovery System (MACRS), and current federal and State of Illinois corporate income tax rates. The yearly components used to calculate the levelized fixed charge rate are summarized in Tables 17 and Table 18.

Multiplying the levelized fixed charge rate of 12.17% for the 20-year sourcing agreement found in Table 16, by the requested amount of pre-approved capital cost of $[redacted] million results in a level annual fixed payment for the project of $[redacted] million. This level fixed payment is included in the total cost of electricity and ratepayer impacts discussed below.

Table 16. Levelized Fixed Charge Rate – 20-year PPA[11].

Capital Structure	
% Debt	55.00%
% Preferred	0.00%
% Equity	45.00%
Cost of Debt	6.82%
Cost of Preferred	0.00%
Cost of Equity	10.00%
Weighted Pre-Tax Cost of Capital	8.25%
Weighted After-Tax Cost of Capital	6.71%
Tax Rates	
Federal Income Tax Rate	35.00%
State Income Tax Rate	7.00%
Replacement Tax Rate	2.50%
Effective Fed/State Income Tax Rate	41.18%
Capital Stock Tax Rate	0%
Gross Receipts Tax Rate	0%
Real Estate Tax Rate	0%
Investment Tax Credit	0%
Book Depreciation Life (Yrs) – Straight Line	20
Tax Depreciation Life (Yrs) – MACRS	20
Levelized Pre-Tax Carrying Charge Rate	12.42%
Levelized After-Tax Carrying Charge Rate	12.17%

[11] The December 20, 2012 ICC Order approved the 55%/45% debt equity structure and rate of return on equity of 10% as reasonable and appropriate for calculation of the level fixed payment in the sourcing agreement. As proposed in the sourcing agreement, the cost of debt to be adjusted on or near the time of operations for changes in applicable Treasury rates and credit spread, which adjustments will apply only to the debt portion of the total capital.

Table 17. Annual Components to the Levelized Fixed Charge Rate – 20 Year PPA

Yr	Book Depr	Return	Interest Exp	State Tax Depr	Fed Tax Depr	ITC	Amort ITC	State Def Tax	Fed Def Tax	Taxes State Cur	Taxes Fed Cur	Realty	Stock	Gross Recpt	Total Charge	Defered Value	Net Charge
1	0.0500	0.0825	0.0375	0.0375	0.0375	0	0.0000		-0.0044	0.0086	0.0286	0.00000	0.00000	0.0000	0.1653	0	0.1653
2	0.0500	0.0784	0.0356	0.0722	0.0722		0.0000		0.0078	0.0046	0.0153	0.00000	0.00000	0.0000	0.1560	0	0.1560
3	0.0500	0.0743	0.0338	0.0668	0.0668		0.0000		0.0059	0.0048	0.0159	0.00000	0.00000	0.0000	0.1508	0	0.1508
4	0.0500	0.0701	0.0319	0.0618	0.0618		0.0000		0.0041	0.0049	0.0165	0.00000	0.00000	0.0000	0.1457	0	0.1457
5	0.0500	0.0660	0.0300	0.0571	0.0571		0.0000		0.0025	0.0051	0.0169	0.00000	0.00000	0.0000	0.1405	0	0.1405
6	0.0500	0.0619	0.0281	0.0529	0.0529		0.0000		0.0010	0.0052	0.0172	0.00000	0.00000	0.0000	0.1352	0	0.1352
7	0.0500	0.0578	0.0263	0.0489	0.0489		0.0000		-0.0004	0.0052	0.0174	0.00000	0.00000	0.0000	0.1299	0	0.1299
8	0.0500	0.0536	0.0244	0.0452	0.0452		0.0000		-0.0017	0.0052	0.0174	0.00000	0.00000	0.0000	0.1246	0	0.1246
9	0.0500	0.0495	0.0225	0.0446	0.0446		0.0000		-0.0019	0.0049	0.0164	0.00000	0.00000	0.0000	0.1190	0	0.1190
10	0.0500	0.0454	0.0206	0.0446	0.0446		0.0000		-0.0019	0.0046	0.0152	0.00000	0.00000	0.0000	0.1133	0	0.1133
11	0.0500	0.0413	0.0188	0.0446	0.0446		0.0000		-0.0019	0.0042	0.0140	0.00000	0.00000	0.0000	0.1076	0	0.1076
12	0.0500	0.0371	0.0169	0.0446	0.0446		0.0000		-0.0019	0.0038	0.0128	0.00000	0.00000	0.0000	0.1019	0	0.1019
13	0.0500	0.0330	0.0150	0.0446	0.0446		0.0000		-0.0019	0.0035	0.0116	0.00000	0.00000	0.0000	0.0962	0	0.0962
14	0.0500	0.0289	0.0131	0.0446	0.0446		0.0000		-0.0019	0.0031	0.0104	0.00000	0.00000	0.0000	0.0905	0	0.0905
15	0.0500	0.0248	0.0113	0.0446	0.0446		0.0000		-0.0019	0.0027	0.0092	0.00000	0.00000	0.0000	0.0848	0	0.0848
16	0.0500	0.0206	0.0094	0.0446	0.0446		0.0000		-0.0019	0.0024	0.0079	0.00000	0.00000	0.0000	0.0791	0	0.0791
17	0.0500	0.0165	0.0075	0.0446	0.0446		0.0000		-0.0019	0.0020	0.0067	0.00000	0.00000	0.0000	0.0734	0	0.0734
18	0.0500	0.0124	0.0056	0.0446	0.0446		0.0000		-0.0019	0.0017	0.0055	0.00000	0.00000	0.0000	0.0677	0	0.0677
19	0.0500	0.0083	0.0038	0.0446	0.0446		0.0000		-0.0019	0.0013	0.0043	0.00000	0.00000	0.0000	0.0620	0	0.0620
20	0.0500	0.0041	0.0019	0.0446	0.0446		0.0000		-0.0019	0.0009	0.0031	0.00000	0.00000	0.0000	0.0563	0	0.0563
21	0.0000	0.0000	0.0000	0.0223	0.0223		0.0000		0.0078	-0.0023	-0.0078	0.00000	0.00000	0.0000	-0.0023	0	-0.0023

Table 18. Annual Components to the Levelized Fixed Charge Rate (cont.) – 20 Year PPA

Yr	Pre-Tax PWF	After-Tax PWF	Net Charge x Pre-Tax PWF	Net Charge x After-Tax PWF		20 Yrs MACRS
1	0.924	0.937	0.153	0.155		3.75%
2	0.853	0.878	0.133	0.137		7.22%
3	0.788	0.823	0.119	0.124		6.68%
4	0.728	0.771	0.106	0.112		6.18%
5	0.673	0.723	0.094	0.102		5.71%
6	0.621	0.677	0.084	0.092		5.29%
7	0.574	0.635	0.075	0.082		4.89%
8	0.530	0.595	0.066	0.074		4.52%
9	0.490	0.558	0.058	0.066		4.46%
10	0.453	0.523	0.051	0.059		4.46%
11	0.418	0.490	0.045	0.053		4.46%
12	0.386	0.459	0.039	0.047		4.46%
13	0.357	0.430	0.034	0.041		4.46%
14	0.330	0.403	0.030	0.036		4.46%
15	0.304	0.378	0.026	0.032		4.46%
16	0.281	0.354	0.022	0.028		4.46%
17	0.260	0.332	0.019	0.024		4.46%
18	0.240	0.311	0.016	0.021		4.46%
19	0.222	0.291	0.014	0.018		4.46%
20	0.205	0.273	0.012	0.015		4.46%
21	0.000	0.000	0.000	0.000		2.23%

7. Ratepayer Impact Analysis

7.1. Results

The annual incremental rate impact for the oxy-combustion project based on the 20-year sourcing agreement term approved by the ICC on all retail customers in the ComEd and Ameren service areas is shown in Figure 8. The Reference Case average customer impact over the term of the sourcing agreement is estimated to be 1.52 \$/MWh (0.152 cents/kWh) or only a 1.32% increase above the May 2009 bundled retail rates, which is well below the statutory rate cap of 2.015%[12]. These impacts compare favorably with those submitted by FutureGen with the IPA in October 2012.[13]. The ICC's Order of December 20, 2012 stated that these project costs are to be recovered through a new, or modification of an existing tariff from all ComEd and Ameren retail customers through a competitively neutral charge.

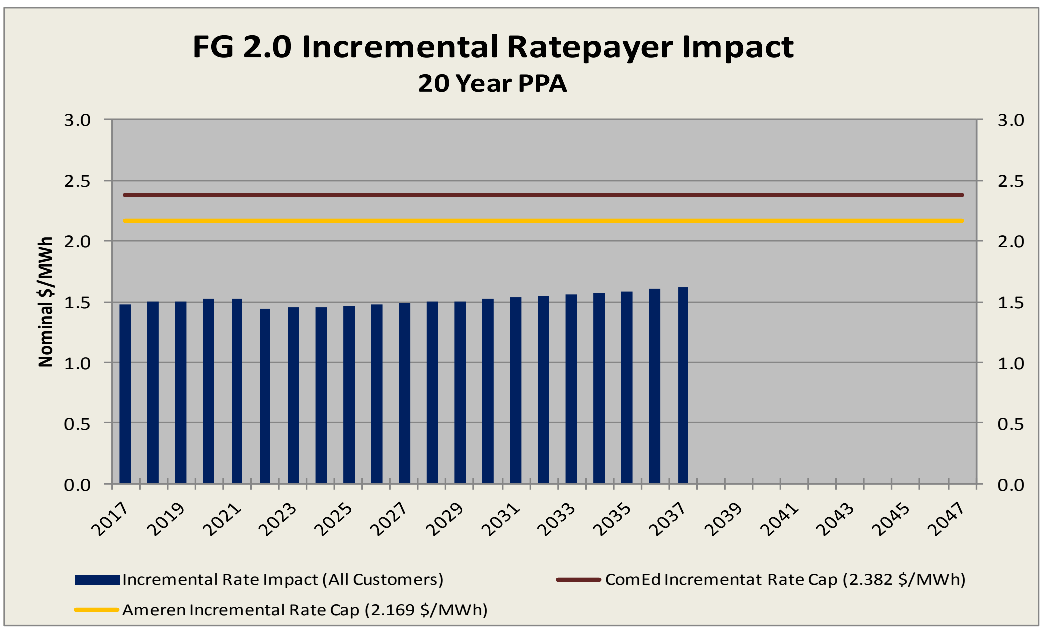

Figure 10. Incremental Ratepayer Impact

[12] The IPA Act statutory rate cap is determined as 2.015% of the amount paid per kilowatt hour by eligible ComEd or Ameren customers during the year ending May 31, 2009. As defined in the previous sentence the statutory rate cap for ComEd eligible retail customers is 2.382 \$/MWh and for Ameren eligible retail customers is 2.169 \$/MWh.

[13] The average customer rate impact provided in the October 2012 Project Cost and Ratepayer Impact Analysis Report for the proposed 30-year term of the sourcing agreement were estimated to be 1.505 \$/MWh (0.1505 cents/kWh) or only a 1.31% increase above the May 2009 bundled retail rates.

Table 19. Reference Case Ratepayer Impact

[TABLE REDACTED]

The incremental customer rate impact was determined by taking the difference between the annual cost-of-service or project revenue requirement and the revenues received from selling the generation output of the project into the Midwest Independent System Operator (MISO) wholesale energy market. This difference was then expressed in dollars per MWh by dividing the resulting cost differential by the forecasted retail load for the ComEd and Ameren service areas. The annual cost-of-service or project revenue requirement is a summation of the capital recovery component, fuel component, fixed and variable non-fuel operating expenses including the transportation and storage of the captured CO_2, less any other expected product revenues (i.e., installed capacity sales, ancillary services, sale of excess CO2, etc.).

7.2. Cost of Power

The Alliance's ratepayer impact analysis was based on the Reference Case cost of power using the formula rate cost components described in the sourcing agreement, expressed in nominal year dollars, is summarized in Table 20 The Reference Case cost of power was developed using the project's capital costs, operating costs, capital and financing structure, and retail load growth within the ComEd and Ameren service areas that have been presented previously in this report, as well as the expected annual level of generation and fuel consumption, and a forecast of MISO wholesale energy prices. These key assumptions are summarized below:

- A level fixed payment of $[redacted] million based per year for the 20-year sourcing agreement based on the total amount of "net" project capital of $672 million and the levelized fixed charge rate shown in Table 16 in Section 6;

- Generation output and fuel heat input as summarized in Table 21;
- Purchased power costs for the projects auxiliary loads of 68.7 MW (inclusive of the ASU) based on Ameren' distribution tariff rates, MISO transmission tariff rates, and a forecast of wholesale on-peak and off-peak electricity prices at the Indiana Hub as shown in Table 22, which is a proxy for the Meredosia nodal price;
- Non-fuel fixed and variable operating costs as summarized in Section 2 and 3;
- The "expected" delivered price forecast for Illinois No.6 and PRB coal developed by John T. Boyd as described in Section 4;
- A value for installed capacity sales of $7,647/MW/yr, which is credited against the fixed capital charges, based on the results of IPA's recently completed auction for capacity products for Ameren service area; and
- An annual inflation rate of 2.5% for non-fuel fixed and variable operating expenses and the capacity credit

The Reference Case cost of power is expected to increase slightly between 2017 and 2019 due to increasing fuel and non-fuel operating costs and an initial lower level of generation output. In 2020, the cost of power will decrease due to an increase level of generation out and lower CO_2 storage operating costs. The plant is assumed to operate at this higher level of generation output throughout the remaining term of the 20-year sourcing agreement.

Fuel and the majority of non-fuel operating expenses increase at the assumed 2.5% rate of inflation. Certain non-fuel operating costs such as local taxes, financing fees, and components of the CO_2 storage project remain constant or decline through the term of the sourcing agreement. The capital recovery component of the cost declines slightly over time because of the assumed credit for installed capacity sales (which are assumed to grow with the 2.5% rate of inflation).

Table 24. Reference Case Cost of Electricity – 20-year PPA

[TABLE REDACTED]

Table 25. Generation Output and Fuel Input

Calendar Year	Contract Year	Gerneration Output MWh/yr	Fuel Input, MMBtu/yr
2017	1	576,931	5,001,532
2018	2	1,153,863	10,003,065
2019	3	1,153,863	10,003,065
2020	4	1,307,711	11,336,807
2021	5	1,307,711	11,336,807
2022	6	1,307,711	11,336,807
2023	7	1,307,711	11,336,807
2024	8	1,307,711	11,336,807
2025	9	1,307,711	11,336,807
2026	10	1,307,711	11,336,807
2027	11	1,307,711	11,336,807
2028	12	1,307,711	11,336,807
2029	13	1,307,711	11,336,807
2030	14	1,307,711	11,336,807
2031	15	1,307,711	11,336,807
2032	16	1,307,711	11,336,807
2033	17	1,307,711	11,336,807
2034	18	1,307,711	11,336,807
2035	19	1,307,711	11,336,807
2036	20	1,307,711	11,336,807
2037	21	653,856	5,668,403
2038	22	-	-
2039	23	-	-
2040	24	-	-
2041	25	-	-
2042	26	-	-
2043	27	-	-
2044	28	-	-
2045	29	-	-
2046	30	-	-
2047	31	-	-

Table 26. Wholesale Power Price Forecast

Calendar Year	Contract Year	Indiana Hub Peak, $/MWh	Indiana Hub Off-Peak, $/MWh	Indiana Hub ATC, $/MWh
2012		31.72	22.25	26.66
2013		36.85	26.23	31.18
2014		39.73	28.19	33.56
2015		42.15	28.96	35.10
2016		44.61	30.65	37.15
2017	1	47.07	32.34	39.20
2018	2	49.41	33.95	41.15
2019	3	51.73	35.54	43.08
2020	4	54.09	37.16	45.05
2021	5	56.53	38.84	47.08
2022	6	59.05	40.57	49.18
2023	7	61.81	42.46	51.47
2024	8	64.51	44.32	53.73
2025	9	66.12	45.43	55.07
2026	10	67.78	46.57	56.45
2027	11	69.47	47.73	57.86
2028	12	71.21	48.92	59.30
2029	13	72.99	50.15	60.79
2030	14	74.81	51.40	62.31
2031	15	76.68	52.69	63.86
2032	16	78.60	54.00	65.46
2033	17	80.56	55.35	67.10
2034	18	82.58	56.74	68.77
2035	19	84.64	58.16	70.49
2036	20	86.76	59.61	72.25
2037	21	88.93	61.10	74.06
2038	22	91.15	62.63	75.91
2039	23	93.43	64.19	77.81
2040	24	95.77	65.80	79.76
2041	25	98.16	67.44	81.75
2042	26	100.61	69.13	83.79
2043	27	103.13	70.86	85.89
2044	28	105.71	72.63	88.04
2045	29	108.35	74.44	90.24
2046	30	111.06	76.31	92.49
2047	31	113.84	78.21	94.80