STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

The Honorable Members of the Illinois General Assembly
State House
Springfield, Illinois

Dear Honorable Members of the Illinois General Assembly:

Pursuant to Section 1-75(d)(4)(ii) of the Illinois Power Agency Act, the Illinois Commerce Commission submits the attached Analysis of the Taylorville Energy Center Facility Cost Report.

The Illinois Clean Coal Portfolio Standard Law ("Clean Coal Act"), created by the enactment of P.A. 95-1027, requires the Illinois Commerce Commission to submit a report to the General Assembly setting forth its analysis of a Facility Cost Report filed by the initial clean coal facility in Illinois. Tenaska Taylorville, LLC, as the managing member of Christian County Generation, LLC, is responsible for preparing, completing and delivering the Facility Cost Report for the Taylorville Energy Center, Illinois' initial clean coal facility.

The Illinois Commerce Commission's Analysis of the Taylorville Energy Center Facility Cost Report and the attached reports and documents are provided to assist the General Assembly in deciding whether or not to enact authorizing legislation and issue the approvals set forth in Section 1-75(d)(4)(iii) of the Clean Coal Act. Public comments and documents submitted by interested parties during the public comment period are also attached to this report.

Sincerely,

Manuel Flores
Acting Chairman

John Colgan
Acting Commissioner

Sherman Elliott
Commissioner

Lula Ford
Commissioner

Erin O'Connell-Diaz
Commissioner

Report to the Illinois General Assembly

Illinois Commerce Commission

Analysis of

The Taylorville Energy Center

Facility Cost Report

September 1, 2010

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Attachments

I. Executive Summary

The Illinois Commerce Commission ("ICC" or the "Commission") recognizes and appreciates the General Assembly's intent in passing Public Law 095-1027 to encourage the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions to advance environmental protection goals and to demonstrate the viability of coal and coal-derived fuels. Therefore, as directed by Section 1-75(d)(4)(ii) of the Illinois Power Agency Act (the "IPA Act"), the Commission hereby submits to the General Assembly an analysis of the Taylorville Energy Center ("TEC") Facility Cost Report ("FCR").[1] Section 1-75(d)(4)(ii) of the IPA Act provides that the Commission's report to the General Assembly

> shall include, but not be limited to, a comparison of the costs associated with electricity generated by the initial clean coal facility to the costs associated with electricity generated by other types of generation facilities, an analysis of the rate impacts on residential and small business customers over the life of the sourcing agreements, and an analysis of the likelihood that the initial clean coal facility will commence commercial operation by and be delivering power to the facility's busbar by 2016. 20 ILCS 3855/1-75(d)(4)(ii).

To assist in preparing this report, the Commission and its Staff retained the economic and engineering consulting services of Boston Pacific Company, Inc. and its subcontractor, MPR Associates, Inc. ("BP/MPR").[2] The Commission also held a joint meeting of its Gas and Electric Policy Committees on August 12, 2010 to discuss the TEC. Representatives of Tenaska, the STOP Coalition, AFL-CIO, the Illinois Coal Association, ComEd, and the Sierra Club, as well as the Mayor of Taylorville and the Chairman of the Christian County Board, attended and discussed the TEC proposal.

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[1] The Commission received the Taylorville Energy Center Cost Report and nineteen related exhibits and posted them to the Commission's website on March 2, 2010. http://www.icc.illinois.gov/electricity/Tenaska.aspx The Commission's press release is included with this report as Attachment C. As noted on the Commission's website, the Commission invited public comments on the TEC documents. Those comments can also be found on the Commission's Tenaska website, and are included in Attachment D to this report.

[2] The BP/MPR analysis is included with this report as Attachment A. A description of the consultants' qualifications is also included as Attachment B to this report.

A. <u>Key Findings</u>

With respect to the topics over which the General Assembly specifically requested feedback, the Commission finds the following:

- **The cost associated with electricity generated by the TEC is substantially higher than that which is associated with other types of generation facilities** – as described more fully herein, the TEC's expected base case electricity cost of $212.73 per MWh (or over 21 cents per kWh) would cost significantly more than wind ($88.80 to $121.97), nuclear ($101.45 to $128.03), traditional coal ($141.08 to $153.03), or combined cycle combustion turbine ($154.05 to $160.78) facilities.
- **The rate impacts on residential and small business customers will likely approach or meet the full 2.015% rate impact cap** – should the rate impact cap be met, because there is no concurrent rate impact cap for alternative retail electric suppliers ("ARES"), additional project costs and cost overruns would be disproportionately borne by ARES and their largely commercial and industrial customer base. This scenario would make ARES less cost-competitive and could have a significant adverse impact on the retail competition model adopted by the General Assembly in 1997.
- **The likelihood that the plant could be commercially operable by 2016 is uncertain** – missing elements and details from Tenaska's construction schedule cause the Commission to question the company's proposed timeline, and the start of construction is contingent on whether and when the Illinois General Assembly passes authorizing legislation. If the start of construction is delayed beyond August 2011, the TEC might not commence commercial operation before 2016.

After careful review of the FCR, the Commission concludes that the TEC facility features high costs to ratepayers with uncertain future benefits, and uncertainties that potentially add to already-significant costs.

B. Key Recommendations and Open Issues Surrounding the TEC

Should the General Assembly seek to move forward with enabling legislation, the Commission offers the following recommendations and asks that the General Assembly address the following open issues surrounding the TEC:

- **While the Clean Coal Act ("CCA") currently caps the rate impact on customers of investor-owned utilities, the General Assembly should also consider capping the cost that would be borne by customers of ARES.** Absent such a cap for ARES customers, above market costs of energy produced from the TEC and potential cost overruns could stifle the competitive market and create significant adverse economic impacts.
- **The risk of cost overruns should not be disproportionately borne by ratepayers.** If the General Assembly approves the TEC project, the Commission requests clear authority to condition approval of the Sourcing Agreements and related Sourcing Tariffs on whatever changes the Commission finds just and reasonable, especially but not necessarily limited to changes in the following areas: aligning the company's allowed rate of return with its actual cost of capital, performance standards, risk sharing, remedies for non-performance and/or construction cost overruns, prudence reviews, and the provision of adequate long-term and short-term output forecasts to utilities, ARES, and the Illinois Power Agency.
- **The General Assembly should consider whether the current plant configuration best balances the interests of ratepayers and the goals of the Clean Coal Act**. As discussed further herein, the potential may exist for this configuration to be altered to reduce costs while achieving the environmental benefits of a coal gasification plant as originally proposed.[3] BP/MPR, the Commission's consultants, recommends that "further study should be made of using a conventional Integrated Gasification Combined Cycle design approach"

[3] See Section III, "Overview of the Taylorville Energy Center 'TEC'" below to see the current configuration of the plant and how it has been changed from the original proposal.

and that consideration be given to and evaluation made of a conventional design as a means to significantly reduce the cost of the facility.

- **Further clarity should be sought on the TEC's carbon sequestration plans and costs.** The plant's current carbon sequestration plans and costs are unclear, and the General Assembly should require Tenaska to provide capital and operating costs analyses that fully reflect these costs as well as finalize what sequestration plan will be utilized.
- **A firm schedule should be sought.** The lack of scheduling details for certain elements of the project in the construction schedule introduces uncertainty about the completion date. These elements include (1) construction of the carbon dioxide sequestration infrastructure, (2) construction of an electric transmission line interconnection to transport power from the TEC, (3) construction of a natural gas pipeline interconnection to bring natural gas into the TEC for generating 248 megawatts of its net capacity, (4) construction of a connection to a water source, (5) construction of the air separation plant, and (6) acquisition of required permits. The General Assembly should obtain this information before proceeding with any authorizing legislation.
- **The plant design should be finalized.** Tenaska's proposed plant design continues to evolve. Recently, Tenaska announced that it has been approved to receive $417 million in Federal investment tax credits, provided that it agrees to increase the planned level of CO_2 sequestration beyond the level described in the FCR. Likewise, the possibility that funding that had been intended for FutureGen could become available for the TEC could also alter the final plans for TEC. The General Assembly should seek to clarify the final proposed design for the TEC, and require an updated FCR.
- **The plant's true generation capacity should be determined.** The Commission notes that the CCA requires the initial clean coal facility to have "a nameplate capacity of at least 500 MW when commercial operation commences."[4] The TEC's maximum planned capacity, including the natural gas-

[4] 20 ILCS 3855/1-75(d)(3).

fired capacity, exceeds 500 MW, implying that this requirement would be satisfied. However, if the TEC operated with only coal-derived fuel (i.e., without the contribution of pipeline natural gas), it would produce no more than 448 MW gross[5] or 296 MW net of electric power.[6] As the plant design may be updated to sequester more CO_2 as a condition of recently received Federal investment tax credits, the plant design may change further still and the amount of coal-derived electricity could fall even further below 500 MW.

- **Clarification should be obtained on all external issues before proceeding.** The BP/MPR analysis was focused on the FCR provided by Tenaska. Beyond the FCR, additional permits and other regulatory and financial approvals —some of which may fundamentally alter the scope and cost of the project— are ongoing, or have not been fully vetted by the appropriate authority. Those may fundamentally alter the scope and the cost of this project. Additionally, the ICC's public comment and policy committee hearing processes yielded valuable feedback from diverse stakeholders on the economic and environmental impacts of the TEC. While not directly part of the Commission's analysis, these factors may be important to the General Assembly in deciding whether to authorize this project. Public comments received by the Commission are included in Attachment D to this Report.

C. Additional Issues

The ICC's review of the CCA has also identified the following open issues which should be addressed by the General Assembly:

- It is unclear what is meant by "primarily" in the definition of "clean coal facility" where the CCA states that a clean coal facility uses "primarily" coal as a feedstock.[7] Does coal as feedstock simply need to be greater than 50%, is it 75%, is it 90% of the feedstock or some other percentage?

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[5] 296 megawatts net electric power output + 58 megawatts air separation load + 71 megawatts syngas plant load + 23 megawatts carbon dioxide compressor load = 448 megawatts gross electric power output.

[6] BP/MPR Evaluation, Executive Summary, pages 12-13, 23 and Task 4, pages 5 and 29.

[7] 20 ILCS 3855/1-10.

- Does the General Assembly determine the prudence and reasonableness of the Sourcing Agreement or does the ICC? If the ICC is to determine the prudence and reasonableness of the Sourcing Agreement, then the ICC requests 180 days rather than 90 to make such a determination.
- The General Assembly should review the formula rates and the role of the ICC and FERC. The language should clearly state that the formula rate inputs are reviewed before any charges are assessed to utilities and ARES. It should be made clear that the obligation of utilities and ARES to purchase the output from the facilities is (1) subject to approval by the ICC on the justness, reasonableness and prudence of the inputs to the formula rates in the sourcing agreements, followed by (2) FERC acceptance of the ICC-approved inputs.
- Clean coal energy needs to be defined. Is all the output from a clean coal facility considered clean coal energy as long as coal is the primary feed stock, or is it just the energy coming from the coal?
- The purpose and effect of General Assembly approval of (A) the projected price and (B) the projected impact on customers is not clear. Does the legislature intend to set a limit on the price paid per kWh for customers to limit the impact on those customers? If so, the Commission recommends that the Clean Coal Act language be revised to make legislative intent clear. If the intent and intended effect of approving prices and impacts is informational only, then the Commission recommends that intent be clarified as well.
- What are the plans by Tenaska to include minority, female, and persons with disabilities in their procurement plans, as well as to work with labor groups on project management and labor agreements?

II. Introduction and Information Required by the CCA

The Commission hereby submits to the General Assembly an analysis of the Taylorville Energy Center Facility Cost Report ("FCR"). Section 1-75(d)(4)(ii) of the Illinois Power Agency Act ("IPA Act"), 20 ILCS 3855/1-1 et seq.[8] provides that the Commission's report to the General Assembly

> shall include, but not be limited to, a comparison of the costs associated with electricity generated by the initial clean coal facility to the costs associated with electricity generated by other types of generation facilities, an analysis of the rate impacts on residential and small business customers over the life of the sourcing agreements, and an analysis of the likelihood that the initial clean coal facility will commence commercial operation by and be delivering power to the facility's busbar by 2016.[9]

The Illinois Clean Coal Portfolio Standard Law ("Clean Coal Act" or the "CCA") was created by the passage of Public Act 095-1027, and added subsection (d) to Section 1-75 of the IPA Act. As required by Section 1-75(d)(4)(ii) of the IPA Act, this document is a report prepared by the Illinois Commerce Commission ("Commission"), in consultation with the Illinois Power Agency ("Agency"), containing the Commission's analysis of the Facility Cost Report submitted on February 26, 2010, by the owner of the proposed initial clean coal facility, Christian County Generation, L.L.C. ("CCG").

The proposed initial clean coal facility is known as the Taylorville Energy Center ("TEC"). An affiliate of Tenaska, Inc., Tenaska Taylorville, LLC ("Tenaska"), is the managing member of CCG.

This report addresses whether there is compliance with the Clean Coal Act, and identifies risks and concerns relative to the TEC proposal to assist the General Assembly in deciding whether to enact authorizing legislation and issue the approvals set forth in Section 1-75(d)(4)(iii) of the IPA Act.[10]

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[8] 20 ILCS 3855/1-75(d).
[9] 20 ILCS 3855/1-75(d)(4)(ii).
[10] 20 ILCS 3855/1-75(d)(4)(iii).

The Commission retained the economic and engineering consulting services of Boston Pacific Company, Inc. and its subcontractor, MPR Associates, Inc., ("BP/MPR") to assist in preparing this report. These consultants provided an independent written evaluation of the FCR (the "BP/MPR Evaluation"). The BP/MPR Evaluation includes an Executive Summary and Task Reports 1 through 7, and is attached to and incorporated by reference into this report as Attachment A. The consultants' qualifications are included in Attachment B.

The BP/MPR Evaluation includes an Executive Summary and seven Task Reports.

Table 1
BP/MPR Evaluation Task Reports

Task 1 Report	A Background Review of IGCC and Carbon Capture and Sequestration Projects to Date
Task 2 Report	An Assessment of Taylorville's Compliance with the Illinois Clean Coal Portfolio Standard Law
Task 3 Report	Assessment of Reasonableness of Capital Costs and Operation Costs for the Proposed Taylorville Energy Center
Task 4 Report	Assessment of Potential for the Taylorville Energy Center to Come On-Line as Planned and Within the Proposed Timeframe
Task 5 Report	An Assessment of the Ability to Finance the Taylorville Facility
Task 6 Report	A Comparison of Taylorville Electricity Costs with Those of Other Generation Options and An Assessment of Taylorville's Effect on Other Market Participants
Task 7 Report	An Analysis of the Long-Term Rate Impacts of Taylorville on Illinois Customers

This Commission report relies extensively on the analysis prepared by the consultant, BP/MPR, and refers to the BP/MPR review in the narrative and footnotes. In addition, Commission staff contributed to the analysis, conclusions and recommendations.

III. Overview of the Taylorville Energy Center ("TEC")

The TEC is designed as a "hybrid" integrated gasification combined cycle generating plant ("IGCC") that is to include a plan to capture and store in the ground carbon dioxide emissions.[11] BP/MPR describes the TEC as follows:[12]

> Taylorville is a proposed electric power plant which would first convert Illinois coal into the equivalent of natural gas;[13] this is called either substitute or synthetic natural gas and its acronym is SNG. Taylorville would then use this SNG to produce electricity with a modern, efficient power plant using a technology called combined cycle generation. The term used for the overall technology is Integrated Gasification Combined Cycle and the acronym is IGCC. Since Taylorville will sometimes sell the SNG as natural gas rather than using it to produce electric power, its sponsor, Tenaska, Inc., refers to it as a Hybrid IGCC. Note, too, that Taylorville will purchase a substantial amount of pipeline natural gas to supplement its SNG when it wants to produce maximum electricity output.
>
> The most important part of the Taylorville proposal, however, is its plan to capture and store in the ground the power plant emission said to be the primary cause of global climate change. That is, it proposes to capture and store carbon dioxide emissions; the technical term for this is carbon capture and sequestration. We say this is the most important part because a stated purpose of the Clean Coal Law is to "demonstrate the viability of coal and coal-derived fuels in a carbon constrained economy."[14]

As a hybrid IGCC, the TEC will produce gas from coal and then convert that gas into synthetic natural gas – a natural gas equivalent – that can be used to generate electricity or be sold as natural gas. The TEC will also use pipeline-delivered natural gas to generate electricity. The TEC is designed to operate in three different modes.[15]

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[11] The Illinois Power Agency Act (20 ILCS 3855/1-10) states "Clean coal facility" means an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon emissions…".

[12] BP/MPR Evaluation, Executive Summary, page 1.

[13] A clarification to BP/MPR's description: the plant is designed to first produce gas from coal and *then* convert that gas into a natural-gas equivalent. This distinction of the two-step process is important in understanding the primary difference between conventional and hybrid Integrated Gas Combustion Turbine facilities.

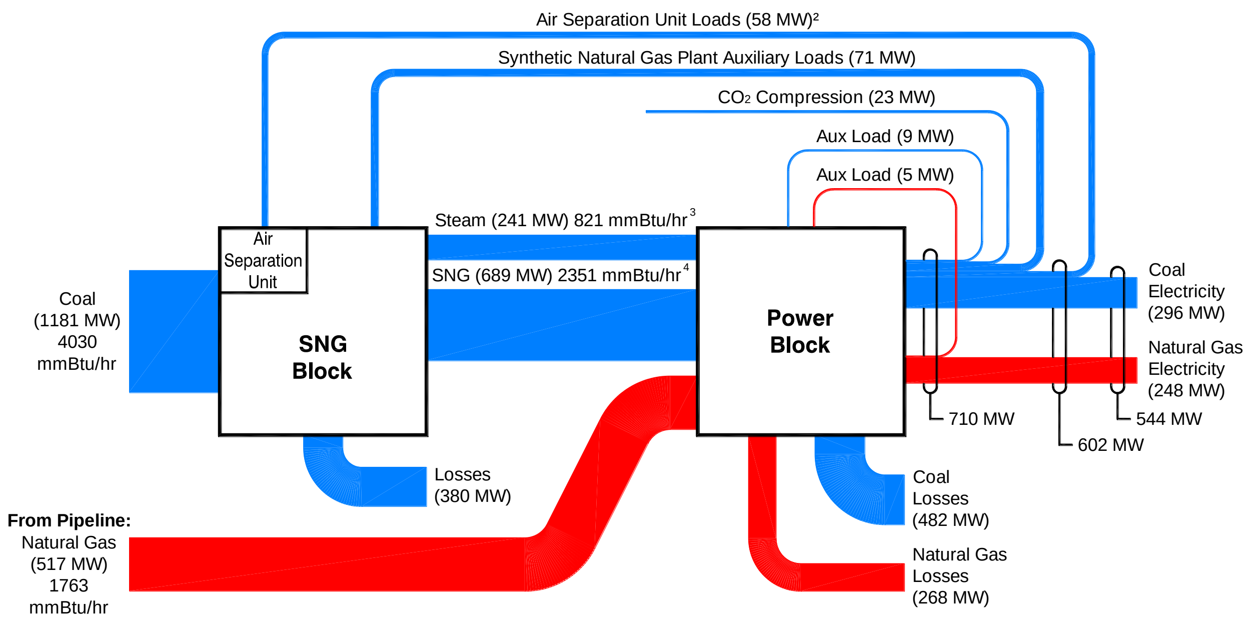
[14] 20 ILCS 3855/1-75(d)(4)(ii).

[15] BP/MPR Evaluation, Task 4 Report, page 33.

Table 2 provides an overview of TEC's operation and net output in the three operating modes.

In Mode 1, the TEC would operate on Illinois coal gasified and converted into SNG, plus a substantial quantity of pipeline natural gas, to produce electricity through the two combined-cycle combustion turbines ("CCCT") at the plant's maximum generating capacity of 602 Megawatts ("MW").[16] Approximately 59%, or 354 MW, results from coal as an input to the process, and the remaining 41% of the output, or 248 MW, results from using pipeline-delivered natural gas.[17]

Figure 1
TEC Operations in Mode 1[18]



In Mode 2, the TEC would operate burning only coal-derived SNG – no pipeline-delivered natural gas – in one of the two CCCTs to produce around 226 MW net electric power and TEC would sell 294 mmBtu/hr[19] of excess SNG to the market.

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[16] BP/MPR Evaluation, Executive Summary, pages 3, 9 and 10. Tenaska represents the net electrical output of the TEC as 602 MW. Tenaska plans to purchase oxygen from a third party and forgo building its own air separation plant. To arrive at the net amount of power that will be new and available to Illinois customers, the 602 MW electrical output must be reduced by the 58 MW auxiliary electric loads required by the third-party air separation plant. The net new power is calculated as follows: 602 MW – 58 MW = 544 MW.

[17] Ibid. Net electric output – new to the system – of 544 MW represents 296 MW derived from coal and 248 MW derived from pipeline-purchased natural gas.

[18] For an illustration of Mode 2 see BP/MPR Evaluation, Task 4 Report, page 31.

In Mode 3, both gasifiers would be turned off, no coal would be used, and the two CCCTs would be fueled solely with 4,113 MMBtu per hour of pipeline natural gas.[20]

Table 2
TEC's Operating and Net Output in Three Operating Modes

	Gasifiers Oper/Avail*	Combustion Turbine Generators Oper/Avail	Steam Turbine Generator Oper/Avail	Coal used?	Pipeline natural gas used?	SNG sales?	Net output from coal	Net output from pipeline gas
Mode 1	2/2	2/2	1/1	Yes	Yes	No	296 MW	248 MW
Mode 2	2/2	1/2	1/1	Yes	No	Yes	226 MW	-
Mode 3	0/2	2/2	1/1	No	Yes	No	-	MW CONF

*"Oper/Avail" is the number of units *operating* versus the number *available*.

It is projected that the TEC would normally operate in Mode 1, and under certain conditions in Mode 2.[21] The TEC would only operate in Mode 3 when there is an outage of the SNG producing portion of the facility.[22]

The description of the three operation modes reveals a key feature in the design of the TEC: a significant portion of the plant's generating capacity relies solely on pipeline-delivered natural gas. The TEC can be viewed as two separate functional generating plants: one that operates on coal-derived synthetic natural gas, and another that operates on pipeline-delivered natural gas unrelated to the use of coal. The TEC is designed to operate on either or both fuels, and, when combined with the plant's methanation facility and other features discussed later in this report, this design has crucial implications for (a) the costs to build and operate the plant, (b) the CCA's requirement that the initial clean coal facility possess a nameplate capacity of at least

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19 One million Btu (mmBtu) as a measure of power applied to natural gas approximately equals 1,000 cubic feet of natural gas.

20 BP/MPR Evaluation, Executive Summary, p. 4.

21 BP/MPR Evaluation, Executive Summary, page 11; BP/MPR Evaluation, Task 4 Report, page 33.

22 BP/MPR Evaluation, Task 4 Report, page 33. The MW output under Mode 3 is considered confidential ("CONF") by TEC and therefore is not presented in this report.

500 MW,[23] (c) carbon emissions, capture and sequestration,[24] and (d) whether the facility "uses primarily coal as a feedstock".[25]

To place the TEC's design into perspective, the following table identifies types of electric generating facilities.

Table 3
Types of Electric Generating Facilities

Type of Plant	Description
Thermal Power Plant	• Power plant in which the prime mover is steam. • Coal or some other fuel is burned. • Water is heated and converted to steam. • Steam spins a turbine which drives an electric generator. • Waste heat is not used in the process.
Single Cycle Gas Turbine (SSGT)	• Natural gas and air are mixed and ignited. • Pressure from the reaction spins turbine blades attached to an electric generator. • Water and steam are not used. • Waste heat is not used in the process.
Combined Cycle Gas Turbine (CCGT)	• Natural gas and air are mixed and ignited. • Pressure from the reaction spins turbine blades attached to an electric generator. • Waste heat from the process is used to convert water into steam to generate additional electricity via a steam turbine. • "Combined" refers to the combination of both processes in a single plant.
Integrated Gasification Combined Cycle (IGCC)	• Electric generation processes are the same as a CCGT. • "Integrated" refers to an additional feature of the plant – coal gasification – that converts coal into a gas that is used to produce electricity at the plant. • In a conventional IGCC design, the gas from the coal gasifier is used directly in the combustion turbines.
Hybrid IGCC	• Same as IGCC with this additional feature: gas from the coal gasifier is first converted to the equivalent of natural gas and then used in the combustion turbines or sold. • This is the design of the Taylorville Energy Center.

The CCA requires the initial clean coal facility to have "a nameplate capacity of at least 500 MW when commercial operation commences."[26] The TEC's maximum planned capacity, including the natural gas-fired capacity, exceeds 500 MW, implying that this requirement would be satisfied. However, if the TEC operated with only coal-derived

[23] 20 ILCS 3855/1-75(d)(3).
[24] Ibid.
[25] 20 ILCS 3855/1-10 (Definitions).
[26] 20 ILCS 3855/1-75(d)(3).

fuel (i.e., without the contribution of pipeline natural gas), it would produce no more than 448 MW gross[27] or 296 MW net of electric power.[28] The coal-derived fuel provides less than 3/5ths of the statutory nameplate capacity requirement.

The sections that follow present forecasts of what it will cost to build and operate the TEC. A useful summary of those costs is referred to as the "annual revenue requirement," which represents the amount of annual revenues that would be necessary in order for the TEC, over 30 years, to recover its expenses and to obtain a return of and on its capital investment.

IV. Taylorville Energy Center's Capital Cost Risks

The Facility Cost Report projects the cost to build the initial clean coal facility, TEC, at $3.5 billion,[29] and identifies the accuracy of this estimate as -10% to +15% resulting in a capital cost range of $3.2 to $4.0 billion. BP/MPR's analysis of the accuracy of the estimate, discussed below, results in a range of -15% to +20% that, when applied to the FCR's $3.5 billion capital cost estimate, results in a total project cost of $3.0 to $4.2 billion.[30]

Another way to state the cost of a generating facility is in terms of dollars per unit of installed capacity, and in this case, the term is dollars per kilowatt ("kW"). The TEC net power output capacity in Mode 1 is projected to be 544 MW, or 544,000 kW. A net output of 544,000 kW at a cost of $3.5 billion results in a cost per kilowatt of $6,474.[31] Later in this report, the cost of the TEC will be compared to other types of generation facilities.

The BP/MPR Evaluation provides an analysis of the capital cost estimate scope, the cost-estimating methodology, the cost estimators' experience and qualifications, the estimate reasonableness, and the estimate accuracy, which are summarized below:

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27 296 megawatts net electric power output + 58 megawatts air separation load + 71 megawatts syngas plant load + 23 megawatts carbon dioxide compressor load = 448 megawatts gross electric power output.

28 BP/MPR Evaluation, Executive Summary, pages 12-13, 23 and Task 4, pages 5 and 29.

29 Details of Tenaska's cost estimate can be found at BP/MPR Evaluation, Task 3, pages 5-7.

30 BP/MPR Evaluation, Task 3 Report, page 24.

31 BP/MPR Evaluation, Task 3 Report, page 19.

A. <u>Capital Cost Estimate Scope</u>[32]

BP/MPR analyzed what has been included in or excluded from the scope of the $3.5 billion estimate.

Most notable is the absence of carbon sequestration costs. The FCR assumes a third-party pipeline ("Denbury pipeline") will be constructed to carry carbon dioxide emissions ("CO_2") to entities that inject CO_2 underground for enhanced oil recovery. BP/MPR concludes the likelihood this pipeline will be constructed is too uncertain, and recommends the TEC cost estimate increase by $44 million to reflect the alternative plan to build local facilities to sequester CO_2 into the on-site Mt. Simon sandstone geologic formation. The $44 million cost is not in the TEC cost estimate[33] and it is unclear whether the time necessary for the construction is in the TEC construction schedule.[34] It is useful to note at this point that Tenaska's economic evaluation of the TEC also relies on revenue from the CO_2 sales that may never occur.[35]

The following table summarizes the additional cost of the carbon sequestration between the third party pipeline versus the Mount Simon sequestration. The far right column of the following table shows the impact of adding $44 million for development of the Mt. Simon formation, adding additional Operations and Maintenance ("O&M") and subtracting off CO_2 revenues from the proposed Denbury pipeline.

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32 BP/MPR Evaluation, Task 3 Report, pages 8-11.
33 BP/MPR Evaluation, Task 3 Report, page 8.
34 BP/MPR Evaluation, Task 4 Report, page1.
35 BP/MPR Evaluation, Task 3 Report, page 28.

Table 4
Sequestration Costs for Denbury Pipeline and Mt. Simon Alternatives

	Base Case (Denbury CO_2 Pipeline)	Mt. Simon Formation Sequestration	Difference
Net Levelized Revenue Requirement (,000)	$762,716	$764,472	$1,757
Net Levelized Subsidy (,000)	$285,959	$287,715	$1,757
Net Levelized Revenue Requirement per MWh Purchased from the TEC	$212.73	$213.22	$0.49
Net Levelized Subsidy per MWh Purchased from the TEC	$79.76	$80.25	$0.49
Net Levelized Subsidy per MWh of Statewide Demand	$2.01	$2.02	$0.01

Additional costs to the project would be the transmission upgrades discussed in Section II of the BP/MPR Task 4 report. According to the report, transmission upgrades will likely be required in both the Midwest ISO and PJM systems. The FCR concludes that $36.4 million in transmission upgrades would be required, which is included in the capital costs estimate for the facility.

The TEC SNG production operation requires an air separation plant for an oxygen supply to the coal gasifiers, but Tenaska does not plan to build such a plant and instead plans to purchase oxygen for the TEC from a third party supplier that would build its own air separation plant. As presented in its FCR, Tenaska's plan reduces the apparent capital costs of the TEC by $191 million[36] and eliminates a 58 MW auxiliary electric load (making the TEC appear to have a 58 MW larger net capacity).[37] However, the $191 million added capital costs for the air separation plant do not disappear: they are simply converted by the third-party supplier into an ongoing charge to the TEC. The additional 58 MW needed to operate the air separation unit are still needed and cannot legitimately be ignored when computing the net output of the TEC.

Recent experience with another IGCC plant demonstrates that there is a real risk that the cost to build the TEC could be even higher than the estimated upper baseline range. On April 16, 2010, Duke Energy Corporation filed accounting testimony with the Indiana

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[36] BP/MPR Evaluation, Task 3, page 8.
[37] BP/MPR Evaluation, Executive Summary, page 7. Also see footnote 16 of this ICC report.

Utility Regulatory Commission which demonstrated that the initial Front End Engineering Design ("FEED") study cost estimate for Duke's Edwardsport, Indiana, conventional IGCC grew by slightly over 45 percent from a $1.985 billion FEED study estimate in early 2007 to $2.35 billion in May 2008 and to $2.88 billion in April 2010.[38] General Electric Corporation and Bechtel were the vendor and contractor who performed the FEED study and arrived at the original $1.985 billion cost estimate for the plant. Both companies have substantial experience and excellent reputations in the field of electricity generation.

B. Cost Estimating Methodology

BP/MPR concluded the methodology is well-documented, and based on a methodical approach that encourages transparency and accuracy. However, the plant mentioned above that has had significant cost overruns likely also had a properly conducted cost estimation.

While there certainly have been power plants constructed that have been completed below budget, such as Springfield's recently completed Dallman 4 Power Station,[39] the question of why some projects end up costing substantially more than budgeted has been a subject of ongoing study. For example, Flyvbjerg, Holm, & Buhl studied 258 transportation infrastructure projects and found, among other things, that costs are underestimated in almost 9 out of 10 projects; the likelihood of actual costs exceeding estimated costs is 86%; and actual costs are on average 28% higher than estimated costs; concluding that cost estimates are biased, and the bias is caused by systematic underestimation.[40] Projects coming in over budget are more common than projects coming in under budget. One way to explain this observation is through the more general concept of "optimism bias" – a systematic tendency for people to be over-optimistic about outcomes.

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[38] Docket No. 4311-IGCC4S. Direct Testimony of Mr. Richard W. Haviland, Duke Energy's Senior Vice President of Construction and Major Projects.

[39] See: http://www.cwlp.com/electric_division/generation/Dallman_4.htm

[40] Flyvbjerg Bent, Holm Mette Skamris and Buhl Sø Underestimating Costs in Public Works Projects: Error or Lie? [Journal] // APA Journal. - 2002. - 3 : Vol. 68. - pp. 279-295.

There appears to be multiple causes for optimism bias. Flyvbjerg defines the following categories: technical, psychological, political and economic. Technical sources of optimism bias include imperfect information, such as imperfect forecasting technique, inadequate data, and honest mistakes; scope changes, such as expansions beyond the original design taking place during the project's development and implementation; and poor management, such as failing to perform a detailed analysis of risks. Psychological explanations focus on the mentality of project promoters and forecasters. Political and economic explanations for forecast bias focus on the interests of the various political and economic actors involved.[41]

While the Commission cannot come to any conclusion as to whether any of these factors are likely to impact the FCR cost estimates, it would be remiss to not point out the risks that optimism bias could create for the cost of constructing the TEC.

C. <u>Cost Estimator Experience and Qualifications</u>

The majority of the FCR cost estimates were prepared by Kiewit/Burns & McDonnell, Tenaska, and WorleyParsons. The qualifications of these entities are presented in BP/MPR's Task 2 Report, Appendix C. BP/MPR reviewed the prior cost estimating experience of the companies and concluded that they have the appropriate experience and qualifications to perform the TEC cost estimate.

D. <u>Estimate Reasonableness</u>

BP/MPR concludes "Taylorville [TEC] is an expensive facility by any measure."[42] A breakdown of the TEC according to output derived from coal and output derived from natural gas reveals the following in terms of dollars per unit of installed capacity when TEC is operating in Mode 1:

- Total plant cost is $6,474/kilowatt;
- Cost of the natural gas portion of the facility is $1,500/kilowatt;
- Cost of the coal portion of the facility is $10,641/kilowatt.

[41] Flyvbjerg Bent Procedures for Dealing with Optimism Bias in Transport Planning [Report] = 58924 / The British Department for Transport. - 2004 - http://flyvbjerg.plan.aau.dk/0406DfT-UK%20OptBiasASPUBL.pdf.

[42] BP/MPR Evaluation, Task 3 Report, page 19.

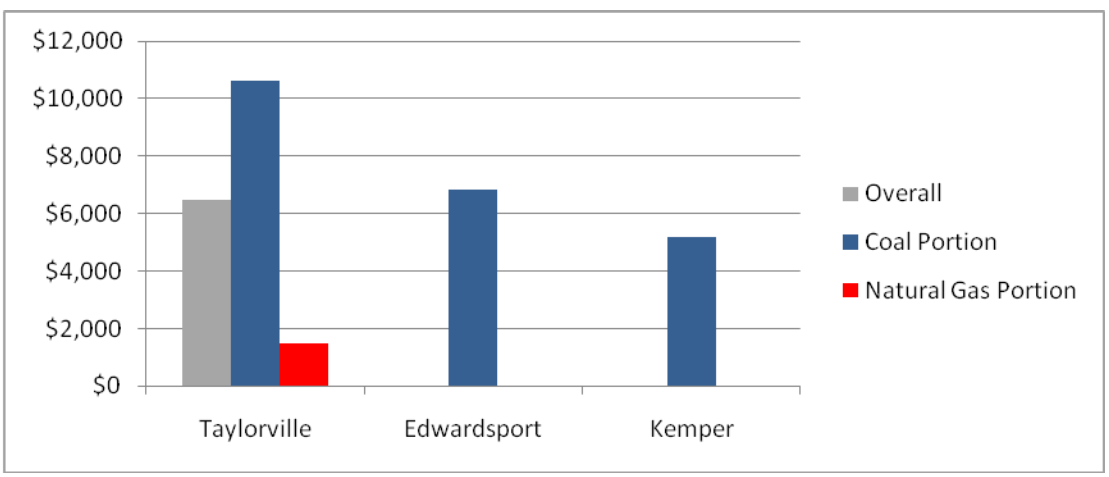
BP/MPR arrives at a key conclusion on this point, stating "the true cost of the clean-coal portion of the plant is masked by the fact that approximately 46% of the electrical capacity is actually from natural gas" and the clean-coal portion of the Taylorville facility is "approximately $10,641 per kilowatt".[43] In other words, the TEC's forecasted total plant cost of $6,474/kilowatt appears comparable to similar plants only because approximately one-half of the output is derived from pipeline natural gas.

BP/MPR's Task 1 Report presents four case studies, stating

> "Each Case Study serves to provide a review of a specific IGCC project, gasification project, or technology in order to highlight (a) the technologies used, (b) the challenges encountered, and (c) the lessons learned."[44]

BP/MPR chose two Integrated Gasification Combined Cycle (IGCC) facilities – the above-referenced Duke Energy Edwardsport facility in Indiana and Mississippi Power Company's Kemper County facility in Mississippi – as being sufficiently similar to the TEC to permit a comparison of the facilities' costs. The following table presents the comparison of the TEC to the Edwardsport and Kemper coal gasification facilities. Note the cost of the coal portion of each facility.

Table 5
Comparison of Taylorville Capital Cost to Other Gasification Facilities
(dollars per kilowatt)



[43] Ibid.
[44] BP/MPR Evaluation, Task 1 Report, page 1.

BP/MPR recommends “further study should be made of…using a conventional Integrated Gasification Combined Cycle design approach”.[45] BP/MPR’s analysis suggests the TEC capital costs can be reduced by using the gas directly from the coal gasifier in the combustion turbine and by eliminating the process that first converts the gas into a natural gas equivalent.

E. Estimate Accuracy

BP/MPR’s analysis of the capital cost estimate’s accuracy is based on terminology and guidance found in the “Standard Classification for Cost Estimate Classification System.”[46] BP/MPR reviewed the completeness of the engineering design, the status of signed contracts for several process areas in the plan, the estimating methodology, the FCR preparation effort, and other considerations. BP/MPR concludes the FCR’s claim of estimate accuracy of -10% to +15% is overly optimistic, and suggests a more reasonable range is -15% to +20%.

V. Taylorville Energy Center’s Operations, Maintenance, Fuel and Other Costs

In addition to capital costs, there will be continuing costs of operating the TEC, including:

- Fuel costs (for pipeline natural gas and coal used in the processes to generate electricity), minus any revenues from the potential sale of excess SNG produced at the plant;
- Operations and maintenance expenses such as labor, maintenance parts and materials, administrative systems, waste disposal, insurance;
- Transmission service costs;
- Air separation service costs (purchase of oxygen and industrial gases);
- Sequestration costs;

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45 BP/MPR Evaluation, Task 3 Report, page 20.
46 BP/MPR Evaluation, Task 3 Report, pages 21-24.

- Carbon dioxide and sulfur dioxide emission allowance costs, net of any tax credits, allowances, or revenues received by TEC due to the capture of carbon dioxide, sulfur, and nitrogen oxide produced by TEC.[47]

The on-going costs are estimated at approximately $404 million per year. As with capital costs, actual on-going costs could vary significantly around this estimate. As discussed below, the BP/MPR Evaluation expresses concern that the FCR's estimates for annual O&M costs are too low.[48]

A. O&M Expenses

The BP/MPR Evaluation provides an analysis of the background of the estimator, the O&M scope and exclusions, and the accuracy of the O&M estimate.[49]

B. O&M Expense Estimator Experience and Qualifications

BP/MPR concludes the operations and maintenance expense estimator, who is also the vendor for the critical gasification island components as well as the combustion turbine and associated auxiliaries at TEC, is qualified in this area.[50] However, as discussed below, BP/MPR identifies several areas of the cost estimate that may be under-estimated.

C. O&M Expense Estimate Scope

BP/MPR concludes the FCR provides a comprehensive evaluation of the predicted costs to operate and maintain the TEC.[51] The cost of fuel (coal and natural gas) is not included in the O&M expense estimate, but is discussed separately below.

A significant item excluded from the O&M expense estimate, but which BP/MPR concludes should be included, is the cost for CO_2 sequestration.[52] BP/MPR reviewed a

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[47] Sulfur dioxide "allowances" are part of the existing "cap-and-trade" policy toward restricting sulfur-dioxide emissions to levels pre-specified by policy makers. Such an approach is thought to minimize the total cost of attaining a given environmental objective. In the FCR and the BP/MPR Evaluation, this same approach is assumed to be used for carbon dioxide emissions as well.
[48] BP/MPR Evaluation, Executive Summary, pages 7.
[49] BP/MPR Evaluation, Task Report 3 Report, pages 26-33.
[50] BP/MPR Evaluation, Task Report 3 Report, pages 26-27.
[51] BP/MPR Evaluation, Task Report 3 Report, page 27.

report prepared for the TEC that estimates the O&M expense for the sequestration pipeline and equipment would be approximately $640,000 per year.[53]

Tenaska has considered two options for sequestering the TEC's CO_2. If neither the preferred nor the back-up plan for carbon sequestration proves feasible, the TEC may have to purchase carbon emission allowances for the CO_2 that it has committed to sequester and the TEC operation will have to forego planned CO_2 sales revenue. Section 1-75(d)(3)(D)(v) of the IPA Act provides that "[n]o costs of any such purchases of carbon offsets may be recovered from a utility or its customers."[54] Additionally, the loss of CO_2 sales revenue would increase net TEC O&M costs.[55]

D. Accuracy of the O&M Expense Estimate

The FCR estimates annual O&M expenses, not including fuel costs, to be $67.3 million. BP/MPR, for the reasons listed here, concludes the O&M expenses may be under-estimated and more reasonably quantified as $105 million per year:[56]

- BP/MPR expects capital improvements expenses, as a percentage of total capital costs, to be higher than estimated in the FCR.
- BP/MPR notes the proposed staffing level seems to be in the correct range, but identifies possible understaffing in specific areas.
- TEC's estimator used an optimistic approach to cost estimating in various areas such as inspection durations, methanation catalyst life, and costs for vendors' technical field assistants.
- No costs are included for CO_2 sequestration.

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52 BP/MPR Evaluation, Task Report 3 Report, page 28.

53 Ibid.

54 Presumably, any reference to "utilities" in paragraphs (3) and (4) of subsection (d) of Section 1-75 of the IPA Act should also be read to include ARES since they are required to execute sourcing agreements under the terms of those paragraphs by Section 16-115(d)(5)(v) of the PUA. 220 ILCS 5/16-115(d)(5)(v). However, the General Assembly may want to consider clarifying this point if it enacts authorizing legislation.

55 BP/MPR Evaluation, Executive Summary, pages 13-14.

56 BP/MPR Evaluation, Executive Summary, pages 5-6, and Task 3 Report, page 2.

E. Fuel Costs

The FCR forecasts growth in natural gas prices over the TEC's life range from three to five percent per year. As recent experience shows, forecasting gas prices over even a much shorter term is fraught with uncertainty. Over the past two years, the average price for natural gas in the U.S. has ranged from a high of $12.48 per thousand cubic feet in July 2008 down to $5.34 in September 2009.[57] Higher pipeline natural gas costs would raise the price to generate electric power with pipeline-delivered natural gas at the TEC. Lower natural gas costs would have the effect of driving down the market price of electricity and make TEC-generated clean coal electricity even less cost-competitive.

The BP/MPR Evaluation contends that there is significant uncertainty regarding the FCR's estimates of future coal costs.[58] Higher coal costs would raise the price of operating the plant. The result of higher coal transportation costs is shown in Table 8 of this report.

VI. Cost Comparisons with Other Types of Generating Plants

BP/MPR's Task 6 Report is devoted to comparing the cost of the TEC to the cost of six other types of new generating facilities, including nuclear, conventional coal, combined cycle combustion turbine using pipeline natural gas, the single cycle combustion turbine ("SCCT") also using natural gas, solar photovoltaic and wind.

BP/MPR's cost model analyzes the annual revenue requirement over the life of the plant's expected life as based on estimated capital, O&M, and fuel costs, and divides this amount by the expected annual energy produced stated in megawatt hours ("MWh"). The results are presented in dollars per MWh.

BP/MPR's analyses are based on various assumptions including low and high capital costs, natural gas prices scenarios, and CO_2 allowance price scenarios. Similarly,

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[57] "Monthly U.S. Natural Gas Citygate Price." *U.S. Energy Information Administration.* Web. 1 Jun 2010. <http://www.eia.doe.gov/dnav/ng/hist/n3050us3m.htm>.

[58] BP/MPR Evaluation, Executive Summary, page 8.

some categories of costs were not included in the study. For example, because specific locations of power plants are not stated, transmission-related costs are not included in the study. BP/MPR states their results compared favorably to those from a similar study performed by PACE on behalf of Tenaska.

In the Base Case scenario, BP/MPR found that the TEC's cost of $212.73 per MWh of electrical output—equivalent to over 21 cents per kilowatt-hour ("kWh")—would exceed that of all the other technologies, except solar and the virtually obsolete SCCT. The results do not change under any combination of emission costs or natural gas prices.[59] The tables below show the comparison with the BP/MPR base case assumptions for the TEC. It may be surprising to see that wind and nuclear are the first and second least expensive options on the list – even less expensive than a conventional coal plant. The primary reason for this is that these technologies (as well as solar) do not emit CO_2, while all the fossil fuel technologies on the list do. Hence, under the Base Case scenario shown, the cost of acquiring CO_2 allowances to operate a conventional coal plant is high enough to eclipse the cost advantage that coal otherwise would have over wind and nuclear technologies.

Table 6
Base Case Cost per Unit:
TEC Compared to Other Generating Technologies
($/MWh)

	Low Capital Costs	High Capital Costs
Wind	$88.80	$121.97
Nuclear	$101.45	$128.03
Coal	$141.08	$153.03
Combined Cycle Combustion Turbine	$154.05	$160.78
Taylorville Energy Center	**$212.73**	**$212.73**
Single Cycle Combustion Turbine	$330.12	$354.74
Solar PV	$328.12	$511.05

59 BP/MPR notes the two key risks over the life of the plant are natural gas prices and the cost of CO_2 allowances. To account for these risks, BP/MPR conducted additional analyses, and the conclusion did not change under any combination of emission costs or natural gas prices.

Table 7
Base Case Cost per Unit:
TEC Compared to Other Generating Technologies
(Cents/kWh)

	Low Capital Costs	High Capital Costs
Wind[60]	8.9¢	12.2¢
Nuclear[61]	10.1¢	12.8¢
Coal	14.1¢	15.3¢
CCCT	15.4¢	16.1¢
TEC	**21.3¢**	**21.3¢**
SCCT	32.8¢	35.5¢
Solar PV	33.0¢	51.1¢

BP/MPR concludes, "[t]he bottom line from our analysis is that the Taylorville project is much more expensive than most competing alternate technologies, even accounting for key risks going forward."[62] BP/MPR also notes that Tenaska's consultant has similar conclusions:

> PACE finds the Taylorville project is more expensive (or, in one case, about equal to) nuclear, coal and wind projects and less expensive than solar PV and natural gas combustion turbine projects. This matches our findings. The one exception is natural gas combined cycle projects, which PACE finds are less expensive than Taylorville only in the low capital cost case. It appears that this discrepancy is driven by the relatively low capacity factor that PACE assigns to combined cycle units (about 22% versus our 70%). A lower capacity factor means that there are less megawatt-hours to spread the facility costs over.[63]

VII. Consumer Rate Impact

A. Base Case

BP/MPR prepared a Base Case and alternative scenarios to evaluate the rate impact on Illinois consumers when they buy power from the TEC. In the Base Case, BP/MPR's

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60 Wind and other renewable resources are not directly comparable to the TEC due to their intermittent production of energy.
61 The cost of the TEC can best be compared to baseload generation such as nuclear and coal facilities.
62 BP/MPR Evaluation, Task 6 Report, pages 4-5. The "premium" is the amount paid over the market cost for power. BP/MPR calculates the customer-paid premium for each of the thirty years of operation.
63 BP/MPR Evaluation, Task 6 Report, pages 5-6.

analysis shows TEC's annual revenue requirement results in TEC power prices that are always above the market price for power, ranging from a premium of $225 million in 2024 to $331 million in 2032.[64] To allow for further analysis and comparison purposes, the results for the thirty years are levelized, taking into account the time value of money, to arrive at an annual premium of $286 million. Tenaska's consultant finds that the annual average premium is just about the same. BP/MPR states: "Tenaska's estimate of the levelized premium is just a bit higher at $309 million per year (or 65% above levelized market revenues)."[65]

These amounts, whether reviewed year by year or as a levelized annual amount, represent the amount Illinois consumers will annually pay above market prices for TEC's power output according to the Base Case analysis.

The estimated impact of the premium on a customer's bill, relying on Base Case results and estimated annual total electricity use in Illinois of 142.4 million MWh each year, is $2.01/MWh, or about .201¢/kWh.[66] For a typical residential customer using 700 kWh, this additional charge would add approximately $1 to $2 to the monthly bill, or approximately $20 annually. BP/MPR performs a similar calculation on page 10 of their Task 7 Report, and, using the CCA's maximum rate increase of $2.38 per MWh, calculates the premium would add approximately $1.67 to a customer's bill, or around $20 per year. BP/MPR also estimates the rate impact for a typical commercial customer using 36,000 kWh/month. The premium paid for TEC power would add approximately $86 to the customer's monthly bill, or about $1,030 for a full year's bill increase. Actual rate effects will depend on the customer's electricity usage.[67]

BP/MPR's Base Case analysis is based on forecasted annual TEC costs, also referred to as the annual revenue requirement, that are expected to average approximately $763 million per year.[68] Again, this is quite close to Tenaska's own Base Case estimate of

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[64] In the analysis, the TEC's years of operation are 2015 through 2044.
[65] BP/MPR Evaluation, Executive Summary, page 16.
[66] $286 million ÷ 142.4 million MWh = $2.01/MWh, or .201¢/kWh.
[67] BP/MPR Evaluation, Task 7 Report, page 11.
[68] BP/MPR Evaluation, Task 7 Report, page 8.

\$795 million.[69] The revenue requirement amount will be collected from Illinois electric power consumers through the sourcing agreements with the utilities and the Alternative Retail Electric Suppliers ("ARES") and reflects (a) the recovery of and a return on capital costs totaling \$359 million, and (b) the ongoing costs for operations, maintenance and fuel, net of any ongoing credits associated with revenues from selling some of the SNG, captured carbon dioxide, sulfur, and nitrogen oxide allowances produced by the TEC, totaling approximately \$404 million.

The \$763 million is a projection, and <u>not</u> a guarantee. While the projection is based on a considerable amount of engineering and economic cost analysis, it is also based on assumptions about a large variety of unknowns. With respect to these unknowns, the \$763 million baseline revenue requirement represents just one possible scenario (i.e., one set of assumptions about the future value of those unknown variables). There are also other scenarios that lie within the realm of reasonable future possibilities, and their potential to come about creates risk that should be borne by some combination of TEC investors and the electricity customers of the Illinois utilities and ARES.

B. <u>Alternative Scenarios</u>

BP/MPR also evaluated changes in key drivers, or variables, to which the TEC cost and/or the market-based alternative cost are particularly sensitive. Those drivers included future natural gas prices, CO_2 allowance prices (as a proxy for the stringency of future federal carbon regulations), possible TEC construction cost overruns, possible TEC performance problems, such as a slow operations ramp-up rate or a lower-than-expected output level in the SNG plant, higher-than-expected coal transportation costs, additional costs for local carbon sequestration into the Mt. Simon sandstone formation, and other on-going operating costs.[70]

The table below presents just a few of the scenarios contained in the BP/MPR Evaluation that illustrate the impact of varying the assumptions in the analyses.[71]

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69 BP/MPR Evaluation, Executive Summary, page 16.
70 BP/MPR Evaluation, Task 7 Report, pages 4 and 9.
71 BP/MPR Evaluation, Task 7 Report, includes additional sensitivity analysis tables.

Table 8
Alternative Scenario Examples

Scenario	Annual Consumer Subsidy* ($ millions)	Consumer Subsidy per Unit Output** ($/MWh)	Consumer Subsidy per Unit of Statewide Energy Demand*** ($/MWh)
Base Case	$286	$79.76	$2.01
Higher Coal Transportation Costs	$303	$84.58	$2.13
Low Natural Gas Prices	$396	$110.57	$2.78
20% Capital Cost Overrun, 5% Escalation During Construction, and SNG Output Reduced to Guaranteed Levels	$415	$115.78	$2.91

* "Annual Consumer Subsidy" is the additional dollars Illinois consumers will pay each year for TEC power because that power's price exceeds the market price.

** "Consumer Subsidy per Unit Output" represents the annual premium in terms of the facility's annual output. BP/MPR forecasts annual output of 3,585,000 MWh.

*** "Consumer Subsidy per Unit of Statewide Energy Demand" represents the additional amount consumers will pay when considering total electricity use, not just the TEC output, of 142,400,000 MWh per year. See following discussion.

In calculating the last column of the preceding table, BP/MPR assumed a constant level of statewide energy demand of 142,400,000 MWh per year for the 30-year life of the sourcing agreements (2015 through 2044). This level of demand was based on actual 2008 sales escalated to 2015 by the 1990 to 2008 historical load growth rate.[72] That may not be an unrealistic assumption. However, in 2007, the State mandated that electric utilities implement energy efficiency programs standards with incremental electric energy saving goals starting at 0.2% of energy delivered in the year commencing June 1, 2008 and increasing to 2% of energy delivered in the year commencing June 1, 2015 and each year thereafter.[73] These mandated reductions in future demand were not accounted for in the future demand forecast level. By not accounting for the mandated reductions in demand, the forecast may unreasonably

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[72] The assumed constant level of statewide energy demand of 142,400,000 can be found at BP/MPR Evaluation, Executive Summary, p. 2.

[73] Unlike with other resources, a comparison of costs for energy efficiency sufficient to displace a similar amount of energy as would be produced by TEC was not performed. However, for comparison purposes, any reasonable estimate of energy efficiency costs would be substantially lower than the cost of the TEC.

inflate the level of demand over which these costs are spread. Illinois utilities' sales of electricity to ultimate customers in Illinois dropped from 131.2 million megawatt hours in 2008 to 123.7 million megawatt hours in 2009. If the amount of electricity delivered in Illinois continues to decline to meet the savings goals over the 30-year life of the TEC Sourcing Agreements, the amount of the customer-paid premium will be spread over a decreasing amount of energy delivered each year. The result, if energy deliveries were to fall by 2% per year, is that the TEC revenue requirement would exceed the CCA's $2.32 per MWh cap, even using the Base Case assumptions.[74]

C. Market Price Comparisons – Base Case

To place the TEC revenue requirement in perspective and better understand the significance of these numbers, the table below compares the Base Case levelized revenue requirement to the cost of the TEC alternatives, including other new generating facilities, as well as current and future projections of market electric power prices. With the TEC's total costs of $763,000,000 the projected revenue requirement is $212.73 per MWh, or 21.3 cents per kWh.[75]

[74] Commission analysis based on BP/MPR's model.
[75] BP/MPR Evaluation, Executive Summary, pp. 1, 8 and 16.

Table 9
Taylorville Base Case Levelized Average Price versus Recent Market Prices

	Time Period	Price ($/MWh)
Taylorville	30-years beginning 2015	$ 212.73
Spring 2010 energy forward purchases for ComEd for the indicated delivery periods	Jul/Aug 2010 On-peak	$ 46.22
	Jul/Aug 2010 Off-peak	$ 26.50
	Jun 2010 to May 2011 On-Peak	$ 40.86
	Jun 2010 to May 2011 Off-Peak	$ 25.17
Spring 2010 energy forward purchases for Ameren for the indicated delivery periods	Jan/Feb 2011 On-peak	$ 41.77
	Jan/Feb 2011 Off-peak	$ 30.53
	Sep 2011 On-Peak	$ 35.44
	Sep 2011 Off-Peak	$ 19.85
Average of spot energy prices at the ComEd Zone	Jun 2009 – May 2010	$ 29.59
	Jun 2008 – May 2009	$ 41.67
Average of spot energy prices at the Ameren Zone	Jun 2009 – May 2010	$ 28.02
	Jun 2008 – May 2009	$ 38.46
2006 Illinois Auction Price Results for Small to Medium Sized Customers	ComEd: Jan 2007 – May 2008	$ 63.96
	Ameren: Jan 2007 – May 2008	$ 64.77

Under base case assumptions, where the total TEC cost is $763 million per year, the market-based alternative would cost consumers $477 million per year. Hence, Illinois consumers of TEC power would pay a subsidy to the TEC of $286 million per year.

D. Cost Cap Impact Disparity and Potential Effect on Retail Competition

The CCA sets a limit on the increase in customers' rates that can result from purchasing TEC power. The customer impact cap for eligible customers is 2.015% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2009. This amounts to $2.38 per MWh for ComEd customers and $2.17 per MWh for Ameren customers,[76] for a weighted average of $2.32 per MWh.

The customer impact cap, however, only applies to the eligible retail customers of the utilities, and not to the customers of the ARES (who account for more than half of total electricity consumption in Illinois). Because these caps only apply to the utilities' eligible retail customers and not to ARES customers, all TEC costs exceeding the CCA's

[76] BP/MPR Evaluation, Task 7 Report, page 1.

average cap of $2.32 per MWh will be completely borne by the ARES (and to some extent, at least, by their customers). There are scenarios (two of which are included in Table 8 above) under which the average TEC costs in terms of consumer subsidy per unit of statewide energy demand exceeds the $2.32 per MWh cap.[77]

The CCA treats the rate impact on utility and ARES customers differently. That disparate treatment has the potential to conflict with the General Assembly's recent reiteration of "its findings from the Electric Service Customer Choice and Rate Relief Law of 1997 that the Illinois Commerce Commission should promote the development of an effectively competitive retail electricity market that operates efficiently and benefits all Illinois consumers."[78] The TEC proposal is not a competitively neutral option.

As noted in the ICC's Office of Retail Market Development's 2009 Annual Report, over 57,000 electric consumers and over 300,000 natural gas consumers in Illinois have left their electric or natural gas utility and chosen a competitive supplier for their electric or natural gas supply. Based upon these statistics it is clear that Illinois businesses have incorporated the benefits that retail choice provides into their business model. In 2009, 37 alternative retail electric suppliers were licensed to serve non-residential customers, and eight suppliers were eligible to serve residential customers. Thirty alternative retail electric suppliers are actively selling service with eleven alternative retail electric suppliers actively selling in the Ameren service territory and 19 actively selling in the ComEd service territory. The TEC proposal could hinder the recent success that has been seen in the Illinois competitive retail market, hindering choice options for customers and stifling the growth of retail competition in the state.

The lack of a cost impact cap for ARES customers creates uncertainty not only for ARES customers, but also for ARES themselves. And the lack of a maximum ARES subsidy level creates the risk that ARES may not be able to compete for electric utility customers. In addition, even for ARES competing only for customers whose electric service has been declared competitive, and who are therefore receiving only hourly or

[77] Two scenarios are previously presented that reflect low natural gas prices, cost overruns, 5% construction escalation, and reducing SNG output to vendors' guaranteed levels. In those scenarios, the consumer premiums are $2.78/MWh and $2.91/MWh, both exceeding the CCA's average cap of $2.32/MWh.

[78] 220 ILCS 5/20-102(d).

real-time pricing from the utilities, the CCA's uncapped costs to ARES could prove to be too risky for the ARES to compete. If the TEC subsidies applicable to ARES reach a level that makes the electric utilities' variable price offering a viable option for some customers, it would leave the ARES with a smaller customer base to recover those additional subsidies.

In the event the General Assembly enacts authorizing legislation for the initial clean coal facility, the Commission recommends that the General Assembly give serious consideration to a cost impact cap for ARES customers.

VIII. Additional Considerations and Risks

A. TEC Capacity Effect on the Market Price of Electricity

BP/MPR reviewed a report prepared by Pace, a consultant to the TEC project, in which Pace argues that adding the new TEC capacity to the energy market will benefit customers by lowering market prices for energy and capacity.[79] BP/MPR disagrees, and cites deficiencies in the Pace analysis.

The U.S. Energy Information Administration forecasts that 96,670 MW of new capacity will be added in the United States between 2009 and 2015, including 17,170 MW coal.[80] As of May 25, 2010, in the PJM market, there are 101 new generation projects in the active queue (comprising 31,781 MW of proposed new capacity, of which 9,777 MW are in the ComEd control area), and there are 133 projects currently under construction (comprising 7,127 MW of new capacity, of which 428 MW are in the ComEd control area).[81] Data from the North American Electric Reliability Corporation show 2,312 MW of generating capacity under construction in Illinois and 36,344 MW throughout the U.S., including 12,503 MW of capacity using coal as its primary fuel. Indeed, one of the largest plants under construction is a base load coal plant in downstate Washington

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79 BP/MPR Evaluation Task 7 Report, page 11.

80 See Figure 62, Electricity generation capacity additions by fuel type, 2009-2035, on page 67 of the Annual Energy Outlook 2010 with Projections to 2035, Report #:DOE/EIA- 0383(2010), Release Date: May 11, 2010; http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2010).pdf

81 See PJM Regional Queue Summaries, http://pjm.com/planning/generation-interconnection/reg-queue-summaries.aspx

County, Illinois, the 1,600 MW Prairie State Energy Campus.[82] The TEC is not even the only "base load" plant on the drawing board, as NERC data shows approximately 9,000 MW of new coal capacity currently planned for installation, but not yet under construction, within the U.S.[83] Thus, if built, the TEC capacity would be insignificant compared to all other sources of new and existing capacity, and any effect that the TEC might have on market prices could just as easily come from other, significantly less costly generation projects.

B. Conventional versus Hybrid IGCC

A conventional facility directly burns the gas derived from the coal gasification process. A hybrid facility adds a step and converts that gas derived from the gasification process into methane and then burns or sells that natural gas equivalent. BP/MPR's analysis suggests the hybrid design significantly increases the facility's cost and reduces its efficiency.[84] BP/MPR has not developed an independent cost or performance estimate for a conventional facility and stops short of definitively concluding the conventional design is less expensive with better performance. BP/MPR, then, recommends that consideration and evaluation be given to a conventional design as a means to significantly reduce the cost of the facility.[85]

C. TEC Gas Sales

The FCR describes the TEC as having the capability to sell SNG by operating only one of its combustion turbines, instead of two, when market conditions make such sales economically attractive.[86] However, late changes in the TEC design have reduced the attractiveness of this feature to realize revenues from the sale of SNG. The TEC's plan now includes only two gasifiers, not the four gasifiers in the original plans. Two fewer gasifiers, along with other related equipment eliminations, reduced the cost of the TEC significantly, but also reduced the plant's ability to manufacture SNG for sale. With one

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82 Source: Prairie State Energy Campus, http://prairiestateenergycampus.com, verified with data from the North American Electric Reliability Corporation, http://nerc.com.
83 Source: NERC 2009 Electricity Supply and Demand database, http://www.nerc.com/page.php?cid=4|38
84 See the discussion above in which the TEC is compared to similar coal gasification facilities.
85 BP/MPR Evaluation, Executive Summary, page 14.
86 Taylorville Energy Center Facility Cost report, pages 3-4.

combustion turbine shut down, the other combustion turbine will consume 87 percent of the SNG that the TEC can produce with two gasifiers. Only 13 percent of the SNG will be available for sale.[87] At that low level, it is unlikely that synthetic natural gas sales will play a major role in the economics of the TEC.

IX. TEC Demonstration

A. Capture and Sequester Carbon Dioxide Emissions

A key feature of Illinois' initial clean coal facility is the CCA's requirement that the initial clean coal facility captures and sequesters at least 50% of the total carbon emissions that the facility would otherwise emit.[88] BP/MPR notes that during the operating mode with maximum electric output, which uses a combination of SNG and pipeline natural gas (Mode 1), the TEC will capture just under 50% of the CO_2 otherwise emitted. However, when operating in Mode 2 with only coal used, the TEC is expected to capture over 60% of the CO_2 otherwise emitted. Thus, it is reasonable to expect the TEC to exceed the CCA's 50% requirement on an annual basis.[89]

As discussed above in the Capital Cost Risks section of this report, the TEC's sequestration plans are uncertain at this point. The current plan is to sell the CO_2 for oil recovery purposes. This plan requires construction of a pipeline, and proceeding with construction depends on identifying at least one additional source of CO_2. In the meantime, the TEC owners responded to BP/MPR that development of the on-site sequestration option continues. The costs for sequestration options, as noted above, are not included in the TEC costs. The Commission recommends that the General Assembly require the TEC owners to provide capital and operating cost analyses that fully reflect sequestration costs.

An additional concern is that Tenaska announced that it has been approved to receive $417 Million in Federal investment tax credits, provided that it agrees to increase the planned level of CO_2 sequestration beyond the level described in the FCR. The impact

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87 BP/MPR Evaluation, Executive Summary, page 11.
88 20 ILCS 3855/1-75(d)(3)(D)(v).
89 BP/MPR Evaluation, Executive Summary, page 12 and Task 4 Report, page 33.

of the design changes that would be needed to achieve this is unclear at this time, but presumably would add cost and complexity to the project.

B. Uses Primarily Coal as a Feedstock

A "clean coal facility" is "an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon emissions … [.]"[90] While an Illinois clean coal facility is required to use coal as the primary "feedstock" (i.e., as its "primary fuel"), the Clean Coal Act does not define "primarily." As designed, the power output derived from coal as a fuel, at maximum electric output, is approximately one-half of the total plant output, and the other half is derived from using pipeline natural gas as a fuel. As set forth in the BP/MPR Evaluation,[91] "primarily" can be defined a number of ways.

If the General Assembly enacts authorizing legislation for the initial clean coal facility, the Commission recommends defining "primarily" consistent with legislative intent. Ideally, this would include a specific number or percentage along with a specific description of what should be counted in measuring "primarily." For instance, it could be measured based on percentage Btu of fuel input or percentage of electricity output.

C. Emission Rates for Sulfur Dioxide and Other Emissions

The CCA says "[t]he power block of the clean coal facility shall not exceed allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined cycle facility… [.]"[92] BP/MPR evaluated the air emissions from the TEC, and concludes "[c]onsidering the positive performance of the Taylorville facility compared to a traditional coal plant and a natural gas combined cycle plant, we do not have any recommendations for improvement to the Taylorville design with regard to air emissions."[93]

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90 20 ILCS 3855/1-10 (Definition of Clean Coal Facility)(emphasis added).
91 BP/MPR Evaluation, Executive Summary, pages 10-11 and 27.
92 20 ILCS 3855/1-10.
93 BP/MPR Evaluation, Task 4 Report, pages 17–19.

D. Using Coal with a High Volatile Bituminous Rank and Greater than 1.7 Pounds of Sulfur[94]

During BP/MPR's discovery process, Tenaska responded to BP's question on this topic as follows: "[t]he Delivered Fuel Price Study that will be provided as part of the Facility Cost Report will demonstrate that Illinois coal has the characteristics described in the statute (i.e. high-volatile bituminous coal containing > 1.7 lb S/MMBtu)".[95]

E. Nameplate Capacity of at Least 500 MW

The CCA requires the initial clean coal facility to have "a nameplate capacity of at least 500 MW when commercial operation commences."[96] The TEC's maximum planned capacity, including the natural gas-fired capacity, exceeds 500 MW, implying that this requirement would be satisfied. However, if the TEC operated with only coal-derived fuel (i.e., without the contribution of pipeline natural gas), it would produce no more than 448 MW gross[97] or 296 MW net electric power.[98] In deciding whether or not to enact authorizing legislation, the General Assembly should consider that coal-derived fuel provides less than 60% of the statutory nameplate capacity requirement.

The Commission recommends the General Assembly review the nameplate capacity issue in conjunction with its review of "primarily" as used in the definition of a clean coal facility: "an electric generating facility that uses primarily coal as a feedstock".[99] Clearly defining these terms will help to clearly prescribe expectations for the initial clean coal facility.

X. Ability to Finance the TEC

The CCA requires the TEC's owners to provide information on the facility's method of financing.[100] BP/MPR's Task 5 Report is devoted to an assessment of the owners'

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94 20 ILCS 3855/1-10 (Definition of Clean Coal Facility).
95 BP/MPR Evaluation, Task 2 Report, page 32.
96 20 ILCS 3855/1-75(d)(3).
97 296 megawatts net electric power output + 58 megawatts air separation load + 71 megawatts syngas plant load + 23 megawatts carbon dioxide compressor load = 448 megawatts gross electric power output.
98 BP/MPR Evaluation, Executive Summary, pages 10-11 and Task 4 Report, pages 5 and 30.
99 20 ILCS 3855/1-10 (Definition of a clean coal facility).
100 20 ILCS 3855/1-75(d)(4)(i).

ability to finance the TEC. BP/MPR's base case analyses and experience indicate the TEC project has the ability to secure debt and equity investment.[101]

However, BP/MPR observed that TEC's Sourcing Tariff and Agreement "fails to create any incentives for Taylorville to control costs and to ensure good performance and it places far too much risk on Illinois electricity consumers by assuming all cost overruns and all costs of poor performance will be passed through to them."[102] Additional sensitivity analyses include a consideration of risks related to cost overruns and poor performance, and from those analyses, BP/MPR concludes that the debt and equity metrics continue to show that the TEC can be financed with both debt and equity even when the a greater share of risk is allocated to equity investors.[103]

The Commission recommends the General Assembly consider the risks of the project and require that more of those risks be allocated to the facility's investors to encourage the highest level of cost control and performance.

Pursuant to Section 1-75(d)(4)(iii) of the IPA Act, if the General Assembly enacts authorizing legislation approving the TEC, it will also approve "the maximum allowable return on equity for the project."[104] Both the FCR and the BP/MPR Evaluation utilize the 11.5% maximum return on equity allowed by the CCA in their base case assumptions. The General Assembly may find information regarding the effect of other returns on equity on the base case revenue requirement and annual premiums useful in considering whether to set a different "maximum allowable return on equity for the project." The following table provides a calculation of the effect on the base case revenue requirement and annual premiums for the TEC using alternative maximum returns on equity:

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[101] BP/MPR Evaluation, Task 5 Report, Executive Summary, pages 1-2.
[102] Ibid.
[103] Ibid.
[104] 20 ILCS 3855/1-75(d)(4)(iii).

Table 10[105]
Sensitivity Analysis Showing the Effect of Allowed Return on Equity on Levelized Revenue Requirement ("RR") and Levelized Annual Premium

Rate Of Return	Net RR (000s)	Annual Premium (000s)	Net RR per MWh Purchased from Tenaska	Annual Premium per MWh Purchased from Tenaska	Annual Premium per MWh of IL Consumer Demand
5.0%	$664,497	$152,355	$185.02	$42.42	$1.07
6.0%	$676,746	$170,444	$188.48	$47.47	$1.20
7.0%	$690,027	$189,425	$192.23	$52.77	$1.33
8.0%	$704,348	$209,302	$196.27	$58.32	$1.47
8.5%	$711,899	$219,578	$198.40	$61.19	$1.54
9.0%	$719,713	$230,079	$200.60	$64.13	$1.62
9.5%	$727,789	$240,804	$202.88	$67.13	$1.69
10.0%	$736,127	$251,755	$205.23	$70.19	$1.77
10.5%	$744,727	$262,931	$207.66	$73.31	$1.85
11.0%	$753,590	$274,332	$210.16	$76.50	$1.93
11.5%	$762,716	$285,959	$212.73	$79.76	$2.01

XI. Likelihood That TEC Will Commence Operation and Deliver Power by 2016

The CCA requires the Commission to provide in this report "an analysis of the likelihood that the initial clean coal facility will commence commercial operation by and be delivering power to the facility's busbar by 2016."[106] According to the FCR, based on a December 2010 construction start date, the TEC is scheduled to commence commercial operation in December 2014, following a 48-month construction period. However, BP/MPR concluded that a more realistic schedule would provide for an additional 20 weeks, meaning that commercial operation more likely would be delayed until April 2015 (or eight months prior to 2016).[107]

CCG will not proceed with construction of the TEC before the enactment of authorizing legislation. In addition, the lack of scheduling details for certain elements of the project

[105] Computed using "Base Case Taylorville Model.xls". Other than the Allowed Return on Equity, all other input variables are set at the Base Case values, as reported in the BP/MPR Evaluation.
[106] 20 ILCS 3855/1-75(d)(4)(ii).
[107] BP/MPR Evaluation, Executive Summary, p. 5; and BP/MPR Evaluation, Task 4 Report, pages 1-2.

in the construction schedule introduces further uncertainty about the completion date. These elements include (1) construction of carbon dioxide sequestration infrastructure, (2) construction of an electric transmission line interconnection to transport power from the TEC, (3) construction of a natural gas pipeline interconnection to bring natural gas into the TEC for firing of 248 megawatts of its net capacity, (4) construction of a connection to a water source, (5) construction of the air separation plant, and (6) acquisition of required permits.[108] The Commission recommends the General Assembly obtain this information related to items 1 through 6 above before proceeding with the authorizing legislation.

XII. Proposed Clarifications of the Clean Coal Act

The Clean Coal Act revised certain sections of the Illinois Power Agency Act.[109] A review of the Clean Coal Act and the BP/MPR Evaluation makes it apparent that the language of certain sections of the Clean Coal Act could benefit from clarification if the General Assembly enacts authorizing legislation for the TEC. When possible, legislative intent issues related to certain topics are raised in this report in the discussion of that topic. For example, questions regarding the definition of "primarily" as in "a facility that uses primarily coal as a feedstock" are included above in the TEC Demonstration section. The General Assembly may wish to address the following additional potential clarifications to the Clean Coal Act in its consideration of whether to enact authorizing legislation for the initial clean coal facility.

A. <u>The Extent of Commission Review of Sourcing Agreement within 90-days if General Assembly Enacts Authorizing Legislation Approving a Sourcing Agreement</u>

Section 1-75(d)(4)(iv) provides that:

> If the General Assembly enacts authorizing legislation pursuant to subparagraph (iii) **approving a sourcing agreement**, the Commission shall, within 90 days of such enactment, complete a review of such sourcing agreement. During such time period, the Commission shall implement any directive of the General Assembly, resolve any disputes between the parties to the sourcing agreement concerning the terms of such agreement, approve the form of such agreement, **and issue an order finding**

[108] BP/MPR Evaluation, Task 4, page 1.
[109] Public Act 095-1027, Article I, Section 1-5.

> **that the sourcing agreement is prudent and reasonable**." 20 ILCS 3855/1-75(d)(4)(iv) (emphasis added).

It is unclear whether the Clean Coal Act contemplates that the General Assembly will determine the prudence and reasonableness of any sourcing agreement, with the Commission role confined to resolution of disputes between the parties on the terms and the form of the sourcing agreement, or whether the General Assembly intends to leave prudence and reasonableness decisions to the Commission. The directive that the "Commission shall … complete a review of such sourcing agreement" suggests a substantive review and determination by the Commission. However, the directive that the "Commission shall … issue an order finding that the sourcing agreement is prudent and reasonable" could be read to suggest that the Commission is not to engage in a substantive review of the sourcing agreement and is obliged by statute to find it to be prudent and reasonable.

The Commission suggests that the General Assembly clarify whether it intends a substantive review of the sourcing agreement by the Commission. If a substantive review is contemplated, then the Commission further recommends that the General Assembly consider providing a period longer than 90 days for such a review. The Commission suggests that 180 days from an enactment of authorizing legislation would allow a more thorough review of the prudence and reasonableness of a proposed sourcing agreement.

B. <u>Nature and Extent of Periodic Commission Reviews of the Inputs to the Formula Rate</u>

Actual costs to build and operate the initial clean coal facility will not be known at the time of the Commission's initial review of a sourcing agreement. The Clean Coal Act requires the sourcing agreement to incorporate various components, including a formula contractual price.[110] The Clean Coal Act also requires the sourcing agreements to provide for a Commission review of the formula rate inputs:

> (vii) require Commission review: (1) to determine the justness, reasonableness, and prudence of the inputs to the formula referenced in subparagraphs (A)(i)

[110] 20 ILCS 3855/1-75(d)(3)(A).

> through (A)(iii) of paragraph (3) of this subsection (d), prior to an adjustment in those inputs including, without limitation, the capital structure and return on equity, fuel costs, and other operations and maintenance costs and (2) to approve the costs to be passed through to customers under the sourcing agreement by which the utility satisfies its statutory obligations. 20 ILCS 3855/1-75(d)(3)(D)(vii).

Commission reviews of formula rate inputs are required to "occur no less than every 3 years, regardless of whether any adjustments have been proposed, and shall be completed within 9 months."[111] At the same time, the Clean Coal Act recognizes certain federal authority and provides that the sourcing agreements shall:

> (viii) limit the utility's obligation to such amount as the utility is allowed to recover through tariffs filed with the Commission, provided that neither the clean coal facility nor the utility waives any right to assert federal preemption or any other argument in response to a purported disallowance of recovery costs;
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> * * *
>
> (xi) append documentation showing that the formula rate and contract, insofar as they relate to the power purchase provisions, have been approved by the Federal Energy Regulatory Commission pursuant to Section 205 of the Federal Power Act; [and]
>
> (xii) provide that any changes to the terms of the contract, insofar as such changes relate to the power purchase provisions, are subject to review under the public interest standard applied by the Federal Energy Regulatory Commission pursuant to Sections 205 and 206 of the Federal Power Act. 20 ILCS 3855/1-75(d)(3)(D)(viii), (xi) and (xii).

While the foregoing provisions clearly contemplate a substantive Commission review of the formula rate inputs, the meaning of these provisions is ambiguous in certain respects and the Commission/FERC relationship is never addressed directly. First, since the initial clean coal facility is not expected to be operational until the end of the year 2014 at the earliest, it appears there will be at least one review of the inputs before any liability is incurred and charges assessed to utilities or ARES under the sourcing agreements. The General Assembly should consider making this implicit requirement an explicit one. Second, the Clean Coal Act does not specify the order of proceedings before the Commission and FERC. The Commission recommends that the General Assembly make clear that the obligation of utilities subject to Section 1-75(d) of the IPA

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[111] 20 ILCS 3855/1-75(d)(3)(D)(vii).

Act and ARES to purchase the specified output from the initial clean coal facility is subject (i) to explicit approval by the Commission of the justness, reasonableness, and prudence of the inputs to the formula rates included in the sourcing agreements, including but not limited to all capital and operating costs, and (ii) acceptance by FERC of the Commission approved inputs. Absent inclusion of such provisions in the CCA and/or the sourcing agreements, it appears possible for utilities and ARES to incur liabilities based on costs that neither the General Assembly nor the Commission approved or considered to be just, reasonable and prudent.

C. <u>"Clean Coal Energy" Should Be Defined to Remove Any Potential Ambiguity</u>

Section 1-75(d)(3)(B)(iii) of the IPA Act, 20 ILCS 3855/1-1 et seq., provides that the power purchase provisions of the sourcing agreements shall require each utility

> to buy from the initial clean coal facility in each hour an amount of energy equal to [a pro rata share of] **all clean coal energy** made available from the initial clean coal facility during such hour …. 20 ILCS 3855/1-75(d)(3)(B)(iii) (emphasis added).

Similarly, Section 1-75(d)(3)(C)(i) of the IPA Act provides that the contract for differences provisions of the sourcing agreements shall require each utility to contract with the initial clean coal facility in each hour with respect to "… an amount of energy equal to [a pro rata share of] all clean coal energy made available from the initial clean coal facility during such hour …[.]"[112]

"Clean coal energy" is not specifically defined in the IPA Act, but the repeated use of this phrase distinguishes "clean coal energy" from other energy generated by the facility that is not "clean coal energy." The distinction between "clean coal energy," which is required by statute to be fully allocated to the utilities and ARES as discussed above, and other energy produced by the facility, is reinforced by Section 1-75(d)(3)(A)(ii) of the IPA Act which recognizes that there can be "net revenue from the sale of … **energy or capacity derived from the facility and not covered by a sourcing agreement**" and requires such revenue to be "credited against the revenue requirement for this initial

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[112] 20 ILCS 3855/1-75(d)(3)(C)(i)

clean coal facility."[113] The General Assembly could have referred to "all energy made available from the initial clean coal facility," but instead chose to limit sourcing agreement obligations to "all clean coal energy made available from the initial clean coal facility."

The IPA Act defines a "clean coal facility" as "an electric generating facility that uses primarily[114] coal as a feedstock and that captures and sequesters carbon emissions at the following levels: "at least 50% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016 …[.]"[115] Thus, in order to be a clean coal facility, a facility must utilize coal as its primary feedstock for the electricity it generates, and must capture and sequester specified levels of carbon emissions. This definition recognizes that electricity at a clean coal facility may be generated from resources other than coal. This definition is consistent with the distinction between "clean coal energy" and energy from the facility that is not "clean coal energy." However, it might be argued that under this definition of a "clean coal facility" all output is clean coal energy as long as coal is the primary feedstock for the facility. Tenaska seems to believe that utilities and others must buy a pro rata share of all output from the facility.[116] However, the IPA Act does not express the obligation to buy in such terms. Rather, the IPA Act uses the term "clean coal energy." There are references in the IPA Act to "electricity generated by the initial clean coal facility," but these references are general and do not directly contradict the specific reference to "clean coal energy." Nevertheless, parties may argue these references create ambiguity.

As explained above, it appears that "clean coal energy" was intended to mean energy derived from the clean coal process. The Commission recommends that the General Assembly remove this potential ambiguity and provide a definition of "clean coal energy" consistent with legislative intent.

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[113] 20 ILCS 3855/1-75(d)(3)(A)(ii) (emphasis added).

[114] As noted above, the meaning of "primarily" is not certain since the IPA Act does not define "primarily." Merriam-Webster On-Line Dictionary defines "primarily" as "1: for the most part, chiefly." The Commission believes "primarily" would mean something closer to a substantial majority rather than a mere plurality or 50 percent plus 1, and recommends above that this term be defined.

[115] 20 ILCS 3855/1-10

[116] See FCR, pages 12-13.

D. <u>The Purpose of the Legislature-Approved (A) Projected Price and (B) Projected Impact on Customers over the Life of the Sourcing Agreement Is Not Clear</u>

Section 1-75(d)(4)(ii) of the IPA Act, General Assembly approval, provides that:

> [t]he proposed sourcing agreements shall not take effect unless, based on the facility cost report and the Commission's report, the General Assembly enacts authorizing legislation approving (A) the projected price, stated in cents per kilowatt-hour, to be charged for electricity generated by the initial clean coal facility, (B) the projected impact on residential and small business customers' bills over the life of the sourcing agreements, and (C) the maximum allowable return on equity for the project[.] 20 ILCS 3855/1-75(d)(4)(ii).

While it is clear that subsection (C) requires the General Assembly to approve the maximum allowed return on equity for the clean coal facility, the purpose and effect of General Assembly approval of (A) the projected price and (B) the projected impact on customers is not clear. Does the legislature intend to set a limit on the price paid per kWh for customers to limit the impact on those customers? If so the Commission recommends that the Clean Coal Act language be revised to make legislative intent clear. If the intent and intended effect of approving prices and impacts is informational only, then the Commission recommends that intent be clarified as well.

E. <u>The Commission Should Have Clear Authority to Condition Approval of the Sourcing Agreement and Related Sourcing Tariffs</u>

The Commission stresses that this report and its attachments cannot fully delineate the potential effect of a Taylorville Energy Center on Illinois consumers. Another major element to consider is the Sourcing Agreement that Illinois utilities and ARES would be required to sign with CCG if the TEC goes forward. The provisions of those Sourcing Agreements can have a major influence on CCG’s incentives to operate efficiently, predictably, and as cost-effectively as the subject technology allows. Those Sourcing Agreements will determine who will bear the various risks and costs described above.

If the General Assembly approves the TEC project, the Commission requests clear authority to condition approval of the Sourcing Agreements and related Sourcing Tariffs on whatever changes the Commission finds just and reasonable, especially but not necessarily limited to changes in the following areas: aligning the company’s allowed rate of return with its actual cost of capital, performance standards, risk sharing, remedies for non-performance and/or construction cost overruns, prudence reviews, and the provision of adequate long-term and short-term output forecasts to utilities, ARES, and the Illinois Power Agency.

F. Section 1-75(d)(3)(D)(vii)'s Reference To Section 1- 75(d)(3)(A)(iii) And The Reference To "servicing agreement" in Section 1-10 Are Typographical Errors

Section 1-75(d)(3)(D)(vii) provides that the Commission is to "determine the justness, reasonableness, and prudence of the inputs to the formula referenced in subparagraphs (A)(i) through (A)(iii)."[117] The references to subparagraphs (A)(i) through (A)(iii) appears to be a reference to Section 1-75(d)(3)(A)(i) and 1-75(d)(3)(A)(ii).[118] There is no subparagraph (iii) in Section 1-75(d)(3)(A). Accordingly, if the General Assembly enacts authorizing legislation granting approval for a clean coal facility, the Commission Staff recommends that Section 1-75(d)(3)(D)(vii) be revised to delete the reference to "(A)(iii)."

Similarly, Section 1-10 of the IPA Act provides a definition for "servicing agreement," a term not used in the Clean Coal Act or the IPA Act.[119] Staff believes this was intended to be a reference to "sourcing agreement," and should be corrected accordingly with any legislative enactment.

XIII. Contracting and Labor Issues

At the Commission's August 12, 2010 Joint Electric and Gas Policy Committee meeting, Tenaska revealed that they did not have any specific plan in place for the inclusion of minority or female-owned businesses for the project. In addition, the AFL-CIO discussed the successful management and labor agreements that were put into place for the construction of Unit 4 at Springfield's Dallman Power Station that helped bring it in on time and under budget. The Commission encouraged Tenaska to develop plans addressing these issues. The General Assembly may wish to request that Tenaska provide an update and detailed plan.

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[117] 20 ILCS 3855/1-75(d)(3)(D)(vii).
[118] 20 ILCS 3855/1-75(d)(3)(A)(i) and 1-75(d)(3)(A)(ii).
[119] 20 ILCS 3855/1-10.

XIV. Conclusion

This Commission report is intended to accompany the attached BP/MPR Evaluation and other attached documents, rather than as a summary of any of those documents. As such, every issue addressed in the attachments may not be included in this Commission report. The General Assembly is encouraged to review all documents. The Commission is available to discuss issues related to or questions regarding the TEC facilities cost report, this report, the attached BP/MPR Evaluation, or any other technical, economic, or regulatory aspect of this matter.