Comments on "2006 Cost and Performance Comparison of Fossil Energy Power Plants"

With comments 9/27/06

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No.	COMMENT	RESPONSE
1. Comments – Set 1 [RJW]		
1.1 +	First – I would say that this is generally a pretty well-written document. I didn't see a lot of typos, grammatical problems, etc., which would normally be evident. Also, the discussion is straightforward and readable. That said, I think there are some problems, one semi-major (*#1.2*) and one (*#1.3*) that I feel needs to be addressed before the report goes public.	
1.2 +	**Summary:** The report authors acknowledge that they ignore byproduct credits and disposal costs (except for considering the Hg-laden carbon bed from IGCC to be hazardous waste) in their analyses. However, they do not elaborate on what is – or is not – included in their waste disposal costs, which makes the resulting values confusing. I think they need to document what they are, and are not, considering in the waste disposal costs, and address the byproduct credits/disposal costs issue at least qualitatively because of its impact on the decision-making process of some companies (i.e., We Energies would look unfavorably on a design or system that meant they couldn't sell up to 100 percent of their fly ash).	Waste disposal costs are itemized and shown in the cost detail tables for each technology. However, we will add text to emphasize what was included. A qualitative statement will be added regarding byproduct marketability. It is possible that the spend carbon from the IGCC cases will have to be handled as hazardous waste, and if so, a cost should be added for this. Jeff Hoffmann is checking with Eastman to see how they've handled the waste.

No.	COMMENT	RESPONSE
1.3 NETL	Their projection that an advanced PC unit with SCR-ACI-FF-FGD installed will either barely meet the CAMR Hg NSPS (in two cases) or not meet it at all (in two cases) is a gross undermining of CAMR – which DOE had a hand in reviewing and accepting. Addressing the byproduct credit/disposal cost issue could be merely adding a few new paragraphs to the report; addressing this issue may require a complete reanalysis of their calculations and results. I don't think DOE can put out a report that: (1) says advanced PC units won't be able to meet the CAMR Hg NSPS and/or (2) technology beyond BDT (e.g., SCR + ACI) will be needed to meet the NSPS (that was based on only FF + FGD).	See comment 3 in guidance on guidance sheet.
1.4 +	Adobe page 39; document page 19, Exhibit 2-6: The exhibit implies that the NSPS for PM and SO_2 requires a percent reduction for new, modified, and reconstructed units. I don't believe that there is a percent reduction requirement in all cases.	Add text – units have the option of meeting the numerical limit or the % reduction.
1.5 +	Adobe page 39; document page 19, Exhibit 2-6: It seems that the Hg NSPS limits for bituminous coal (at least, since that is the coal being used in the analyses) could/should be included in this table for completeness; or, alternatively, the table could/should refer to another table to be included with the discussion of Hg on Adobe page 40, document page 20, which would include the appropriate Hg NSPS limits.	Will add CAMR limits of 1.9 lb/TBtu or 20 x 10^{-6} lb/MWh.
1.6 -	Adobe page 40, document page 20: The report indicates that the Hg content of the coal for use in the IGCC and PC analyses was taken to be the 99.9th percentile value of the mean of 34 samples (i.e., 0.28 ppm dry). However, if one were to use the EPA's 1999 ICR coal data base, either 952 or 747 samples would be available, depending on whether one included all samples in which Illinois #6 (and Herrin #6) coal was included (i.e., blends) or just samples indicating that only Illinois #6 (and Herrin #6) coal was used, respectively. Using these data, the 99.9th percentile coal Hg values are either 0.18 or 0.17 ppm, respectively. Use of the larger, publicly available, data base would seem appropriate. (Use of the larger data set also impacts on the other coal values [e.g., Btu, sulfur, ash] reported on Adobe page 36, document page 16.)	Not reasonable to change coal design basis now.

No.	COMMENT	RESPONSE
1.7 +	Adobe page 42, document page 22: The last sentence in the first paragraph of section 2.6 states "[c]osts were then adjusted in response to their comments." This statement could be interpreted to mean that DOE made no "sanity" check on the vendor's responses and merely adjusted the costs, regardless of any +/- bias introduced by the vendors in their comments. One would think that DOE would caveat this sentence somehow to indicate (e.g.,) that consistency between vendor cost bases was a goal or that vendor assumptions were reviewed, etc.	Need to better describe where costs came from. Reference sources and explain how costs were developed. See comment 8 on guidance sheet.
1.8 +	Adobe page 43, document page 23: In the last bullet, it is indicated that neither byproduct credits nor disposal costs were considered in the analyses. As these credits/costs can be significant, at least for some facilities, it would seem prudent to include at least a short discussion of even a range of possible factors – both credits and disposal costs – and indicate that such credits/costs could be an additional determining factor in the choice of technology for some companies.	State that the treatment of byproducts is conservative in the sense that we do include disposal costs, and that it was outside the scope of this analysis to do market research on byproduct credits. Please see Jeff Hoffmann for help on the language for this statement.
1.9 +	Adobe page 43, document page 23: Further, fly ash is not noted as one of the "byproducts" which were not considered. This omission is particularly important considering the design of the PC units used in the analyses noted later in the document (i.e., SCR -> ACI -> FF -> FGD). In this design, all of the fly ash would be contaminated with carbon to the extent that it would be unusable for reuse in (e.g.,) the cement or wallboard industries. This would be a significant loss of revenue, with a resulting increase in costs, for a company that strove for total reuse of its fly ash (e.g., We Energies), and an important consideration in their choice of both an overall approach and a specific design. It seems that this point should at least be discussed, with alternatives noted (e.g., installation of a small ACI/FF system downstream of the main ESP or FF so as to retain the "purity" of the majority of the fly ash for reuse) even if the alternatives can't be fully analyzed.	See comment 1.3. Without ACI, the flyash would not be contaminated and could be sold.

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td>1.10
+</td><td>Adobe page 45, document page 25: In the discussion of “Operating and Maintenance Costs” (including consumable costs, which is where the waste disposal costs are presented in the respective tables), it is not clear how waste disposal is handled. As noted above, the report apparently does not consider byproduct credits or disposal costs, but, as noted below, it does consider the Hg-laden carbon bed as being hazardous waste when calculating the disposal cost.</td><td>Itemized disposal costs are provided in cost detail sheets. Additional detail will be provided in the text.</td></tr>
<tr><td>1.11
+</td><td>Adobe page 45, document page 25: Further, the “Waste Disposal” costs listed on the respective “Capital Investment and Operating Cost Requirement Summary” sheets show (basically) little significant difference among the IGCC and PC cases, as follows:

Waste Disposal Costs
<table>
<tr><th>Adobe page</th><th>Document page</th><th>Case</th><th>“Waste Disposal” cost reported, $000</th></tr>
<tr><td>110</td><td>90</td><td>1</td><td>$3,486</td></tr>
<tr><td>142</td><td>122</td><td>2</td><td>$3,833</td></tr>
<tr><td>179</td><td>159</td><td>3</td><td>$3,060</td></tr>
<tr><td>207</td><td>187</td><td>4</td><td>$3,343</td></tr>
<tr><td>243</td><td>223</td><td>5</td><td>$2,991</td></tr>
<tr><td>271</td><td>251</td><td>6</td><td>$3,293</td></tr>
<tr><td>346</td><td>326</td><td>9</td><td>$2,848</td></tr>
<tr><td>373</td><td>353</td><td>10</td><td>$4,024</td></tr>
<tr><td>402</td><td>382</td><td>11</td><td>$2,688</td></tr>
<tr><td>429</td><td>409</td><td>12</td><td>$3,705</td></tr>
</table>
The differences presented in the tables do not appear to reflect the (presumably) significantly greater cost of disposal of the hazardous waste in the IGCC cases. Better explanation of what is, and is not, included, along with the calculation methodology, needs to be provided.</td><td>Again, will add more detail on waste disposal. Assumed $18/ton for flyash, bottom ash and slag and $760/ton for Hg impregnated C from IGCC cases.
Include reference for disposal cost.</td></tr>
<tr><td>1.12
-</td><td>Adobe page 52, document page 32, last paragraph before section 3.1.5: The cost consideration for IGCC Hg control appropriately considers the generated Hg-laden carbon bed as hazardous waste when calculating the disposal cost. This consideration makes it all the more confusing that other credits/disposal costs are not included (see #1.11).</td><td>Ash and slag disposal costs were included. Basis states no credit or cost for byproducts. See comment 1.2</td></tr>
</table>

No.	COMMENT	RESPONSE
1.13 +	Adobe page 215, document page 195: The first paragraph is confusing as to whether the Shell Deer Park IGCC is still operating, or not. The first sentence says that the "demonstration plant has operated successfully since startup in July 1987" – indicating that the unit is still operational. However, the second sentence says that "[b]efore the end of the program in 1991…" – indicating that the unit has been shut down. Further, the third sentence says "…unit produces…" – indicating again, by use of the present tense, that the unit is still operational.	Deer Park was dismantled and the text will be altered accordingly.
1.14 -	Adobe page 215, document page 195: A perhaps interesting omission from the discussion is that of the Pinon Pine IGCC (southwestern U.S.) unit that never became operational (now gas-fired, I believe). If this unit was of one of the three designs selected for case study analysis, it would be useful to provide information on the Pinon Pine unit, its problems, and why it never became operational. Readers of the report will likely be familiar with the unit and wonder at its omission, particularly if it utilized one of the three selected designs.	Transport gasifier not modeled – no reason to mention Pinon Pine.
1.15 NETL	Adobe page 327, document page 307, Exhibit 4-10: The Hg air emissions are listed as being 20 x 10^{-6} lb/MWh, which is the CAMR Hg NSPS limit. However, for bituminous coal, the NSPS limit is based on the use of only an FF and FGD system, not the SCR/ACI/FF/FGD system described for this case. For the given suite of controls, particularly when used on the design bituminous coal, one would expect that the expected Hg emissions would be lower (significantly) than presented, perhaps as low as 90 percent of what is shown (considering that the report states that the ACI system is designed for 90 percent Hg removal). Putting the report out with this assumed suite of controls and only estimating that the NSPS limit will be met (or not – see *#1.16*) would appear to undermine CAMR (i.e., the NSPS can't be met with BDT; SCR, and ACI are required). (Note – both the limit and the underlying control technologies were reviewed, accepted, and approved by DOE during the CAMR interagency review period.)	See comment 3 in guidance on guidance sheet.
1.16 NETL	Adobe page 352, document page 332, Exhibit 4-19, Case 10 Air Emissions: The Hg emission value listed in the exhibit (30.5 x 10^{-6} lb/MWh) would not be in compliance with the CAMR NSPS value (20 x 10^{-6} lb/MWh). Thus, the "case" would not be viable as an alternative, regardless of the Hg removal efficiency assumed. (It is not explained why the estimated Hg emissions for case 9 [identical to case 10 with the exception of CO_2 controls on case 10] are at the CAMR NSPS level, but those for case 10 are 50 percent higher.)	

No.	COMMENT	RESPONSE
1.17 -	Adobe page 408, document page 388, Exhibit 4-41, Case 12 Air Emissions: The Hg emission value listed in the exhibit (27.0 x 10^{-6} lb/MWh) would not be in compliance with the CAMR NSPS value (20 x 10^{-6} lb/MWh). Thus, the "case" would not be viable as an alternative, regardless of the Hg removal efficiency assumed. (It is not explained why the estimated Hg emissions for case 11 [identical to case 12 with the exception of CO_2 controls on case 12] are below the CAMR NSPS level, but those for case 12 are 50 percent higher.)	

No.	COMMENT	RESPONSE
2. Comments – Set 2 [RHW]		
2.1 -	**General Comments:** Overall, the report is well done and creditable. However, I think that the Executive Summary could be strengthened by adding text that provides insight into the relative commercial status of the technologies studied, the differences between the technologies in terms of what was assumed for this project and what has been previously demonstrated at commercial or near-commercial scale, and the results of this project compared to earlier, similar work by the same contractor team covering the same technologies. *Specific suggestions are listed below.*	Study assumption is all technologies commercial for 2010 start-up. No comparison to previous study was conscious decision. Do not compare with previous study, but should address that some technologies are more mature than others and this should be reflected in process contingencies. Refer to comment 7 on guidance sheet.

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td>2.2
-</td><td>Technology Related Comments:

It should be noted explicitly in the Executive Summary and at appropriate points in the text that the GEE, CoP, and Shell gasification technologies studied in this project differ in a number of ways from the technologies utilized in the current ~250-MW demonstration projects in operation at the Tampa Electric Polk Power Plant, Wabash River Repowering project, and Buggenum Power Plant, respectively. These differences between the study assumptions and what is practiced in the demonstration plants should be noted and the potential impacts of these changes on costs, reliability, and availability should be briefly discussed.</td><td>Configurations modeled are described. The comparison suggested here is beyond the scope of the study.
In each major plant section, an explanation of the general rationale for technology selections should be included….e.g. most mature, best performance, lowest cost, nothing else available, etc</td></tr>
<tr><td>2.3
-</td><td>Why are projected availability figures not mentioned that would result from the design bases selected for each of the six IGCC cases? Economics are reported for 85, 80, and 65 percent capacity factors. Can these designs achieve 85 or 80 percent capacity factor? Does it differ significantly among the technologies? Is overall availability reduced by the addition of CO_2 capture equipment? These issues should be discussed.</td><td>85% capacity factor was a study assumption. An availability analysis is beyond the scope of this study.
See comment 6 on guidance sheet.</td></tr>
<tr><td>2.4
-</td><td>Each of the cases is developed on a different set of emission parameters as measured in lbs/kWh generated for the each of the sets of CO_2 capture and non-capture cases. (See the two following the tables). It would be interesting to have the contractors comment about how the LCOE (85 percent capacity factor) would change if each of the competing coal-fueled technologies had to achieve the lowest tabulated values (highlighted in bold type) for each type of emission. To do this they would have to assume values for allowances for each of the pollutants to monetize those differences.

Cases without CO_2 Capture
<table>
<tr><th>Emissions</th><th>GEE IGCC, Lbs/MWh</th><th>CoP IGCC, Lbs/MWh</th><th>Shell IGCC, Lbs/MWh</th><th>PC, Lbs/MWh</th><th>SC PC, Lbs/MWh</th><th>NGCC, Lbs/MWh</th></tr>
</table></td><td>The same control technologies were applied in each like case. The differences in emissions have to do with varying efficiencies and gas compositions. Since they all meet the new NSPS, the analysis suggested is not warranted.
Explain that the same control technologies were</td></tr>
</table>

No.	COMMENT	RESPONSE
		applied in each like case and that all cases meet NSPS even if the quantity of emissions differs.

CO_2	1738	1768	**1687**	1911	1803	799
Hg	9.4×10^{-6}	9.5×10^{-6}	**9.0×10^{-6}**	20×10^{-6}	18.9×10^{-6}	nil
SO_2	0.088	**0.029**	0.053	0.805	0.760	nil
NO_x	**0.456**	0.516	0.499	0.657	0.620	0.061
Particulates	0.053	0.053	**0.051**	0.122	0.115	Nil
LCOE, cents/kWh	54.7	49.4	53.8	49.9	49.7	63.9

Cases with CO_2 Capture

Emissions Lbs/MWh	**GEE IGCC**	**CoP IGCC**	**Shell IGCC**	**PC**	**SC PC**	**NGCC**
CO_2	**118**	250	152	291	258	93
Hg	11.2×10^{-6}	11.6×10^{-6}	**11.0×10^{-6}**	30.5×10^{-6}	27.0×10^{-6}	nil
SO_2	**0.082**	**0.082**	0.085	nil	nil	nil
NO_x	**0.453**	0.514	0.517	0.999	0.886	0.062
Particulates	**0.063**	0.065	0.067	0.186	0.165	Nil
LCOE, cents/kWh	67.6	63.6	74.0	86.3	83.5	83.7

No.	COMMENT	RESPONSE
2.5 -	All of the IGCC systems use an 1800 psi steam cycle. The NGCC system, which employs the same gas turbine, but with a higher firing temperature (because of the lower concentration of water in the exhaust gas), uses a 2400 psi steam cycle. What would the impact on costs be if a 2400 psi steam cycle had been utilized in the IGCC plants instead of the 1800 psi cycle?	The RSC limits steam pressure to 1800 psi. A 2400 psi cycle is not viable.
2.6 -	The following table compares estimated Total Plant Cost (TPC) and the COE derived in this study with the results of a study by the same contractor team in 2000 for several of these technologies (see EPRI Report 1000316). It should be noted that the technologies used in each set of cases vary somewhat. However, it should be noted that the estimated TPC for the CoP IGCC plant increased by about 12 percent, and that for the SCPC plant increased by 18 percent for those cases with and without CO_2 capture; but the TPC of the NGCC plant without CO_2 capture remained essentially constant. Interestingly, the TPC for the NGCC plant dropped by about 9 percent. The major increase in COE is obviously associated with the much higher price of natural gas ($7.46 vs. $2.70 MMBtu). The reasons for these relative changes in TPC should be discussed in the text because they reflect on the value and rate of technology improvement versus the cost of inflation.	A conscious decision was made to not compare this work to previous studies. See comments 7-9 on guidance sheet regarding updates and documentation of costs.
2.7	**Estimated TPC & COE Comparison** **Technology** / **This Report,** LCOE, c/kW (TPC,$/kW) 65% Capacity Factor 2006$ Coal-$1.34/MMBtu NG-$7.46/MMBtu Adv. F Turbine / **EPRI 1000316** LCOE, c/kWh (/TPC, $/kW) 65% Capacity Factor 1999$ Coal-$1.24/MMBtu NG-$2.70/MMBtu F Turbine for NGCC H Turbine for IGCC / **This Report** LCOE, c/kWh (TPC, $/kWh) 80% Capacity Factor 2006$ Coal-$1.34/MMBtu NG-$7.46/MMBtu Adv. F Turbine / **EPRI 1000316** LCOE, c/kWh (TPC, $/kW 80% Capacity Factor 1999$ Coal-$1.24/MMBtu NG-$2.70/MMBtu F Turbine for NGCC H Turbine for IGCC **No CO_2 Capture** GEE IGCC: 6.59 (1557) / — / 5.95 (1557) / — CoP IGCC: 5.95 (1417) / 5.24 (1263) / 5.15 (1417) / 4.51 (1263) Shell IGCC: 6.51 (1593) / — / 5.61 (1593) / — PC: 5.92 (1323) / — / 5.18 (1323) / — SC PC: 5.93 (1355) / 5.15 (1143) / 5.16 / 4.50 (1143) NGCC: 6.75 (507) / 3.35 (505) / 6.47 (507) / 3.07 (505)	

No.	COMMENT	RESPONSE
	Estimated TPC & COE Comparison (cont'd)	

Technology	This Report, LCOE, c/kW (TPC,$/kW) 65% Capacity Factor 2006$ Coal-$1.34/MMBtu NG-$7.46/MMBtu Adv. F Turbine	EPRI 1000316 LCOE, c/kWh (/TPC, $/kW) 65% Capacity Factor 1999$ Coal-$1.24/MMBtu NG-$2.70/MMBtu F Turbine for NGCC H Turbine for IGCC	This Report LCOE, c/kWh (TPC, $/kWh) 80% Capacity Factor 2006$ Coal-$1.34/MMBtu NG-$7.46/MMBtu Adv. F Turbine	EPRI 1000316 LCOE, c/kWh (TPC, $/kW 80% Capacity Factor 1999$ Coal-$1.24/MMBtu NG-$2.70/MMBtu F Turbine for NGCC H Turbine for IGCC
With ~90% CO_2 Capture				
GEE IGCC	8.17 (1950)		7.05 (1950)	
CoP IGCC	7.69 (1861)	6.57 (1642)	6.63 (1861)	5.64 (1642)
Shell IGCC	8.99 (2252)		7.72 (2252)	
PC	10.26 (2358)		8.96 (2358)	
SC PC	9.99 (2368)	8.56 (1981)	8.68 (2368)	7.44 (1981)
NGCC	8.99 (884)	5.41 (943)	8.49 (884)	4.48 (943)

2.8 -	The HHV Efficiency results reported in this study are compared in the table below with the values reported in the 2000 Parsons Study. It should be noted that for the CoP IGCC case, there is a significant drop in HHV efficiency (43.1 percent vs. 38.5 percent). This is probably due to the selection of the Advanced F combined cycle for this study, compared to the higher efficiency H combined cycle used in the earlier study. In 1999, it was assumed that the H turbine would be ready for deployment in IGCC plants by 2010; however, that hope will not be realized. This point should be explained. There is also a drop in SC PC plant efficiency (from 40.5 percent to 38.5 percent) from the previous cases to the new report for those cases without CO_2 capture. Since both plants are using a 3500 psi steam cycle point, this difference should be explained.	The fact that the older study had a lower efficiency with a higher steam cycle must be investigated to determine if there is a problem with the current performance estimate. Similarly, investigate why econamine doesn't show same efficiency improvement for NGCC and SCPC. Econamine appears to be poorer than

No.	COMMENT	RESPONSE
	There are three significant differences in technology in the NGCC plant between the 2000 study and this report. These are the use of: • An advanced F turbine rather than an older F turbine not optimized for syngas • A 2400 psi steam cycle rather than an 1800 psi steam cycle • An Econamine Plus solvent system for CO_2 capture rather than a conventional inhibited MDEA cycle It would be useful for the reader to know how much each of these three differences contributed to a significant reduction in efficiency from 10.9 percent (50.1-39.2) down to 7.2 percent (50.4-43.2) encountered when removing CO_2 from NGCC flue gas in the current study. The point made in the previous paragraph about improved efficiency for the NGCC cycle when CO_2 capture is practiced contrasts with the same drop in SCPC plant efficiency of 11.2 percent in both the previous study and the new study. If the Econamine Plus technology was beneficial in terms of reducing power requirements for the NGG case, it should have had the same effect on the SCPC cases. This issue should be clarified. **HHV Efficiency Results** **This Report, Efficiency, %HHV** / **EPRI 1000316 Efficiency, % HHV** **No CO_2 Capture** GEE IGCC: 38.6 CoP IGCC: 38.5 / 43.1 Shell IGCC: 40.3 PC: 36.3 SC PC: 38.5 / 40.5 NGCC: 50.6 / 50.1	cited in other recent reports. This must be verified and updated if necessary.

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td></td><td>

HHV Efficiency Results (cont'd)

With ~90% CO_2 Capture		
GEE IGCC	32.6	
CoP IGCC	31.3	37.0
Shell IGCC	30.6	
PC	23.9	
SC PC	26.9	28.9
NGCC	43.4	39.2

</td><td></td></tr>
<tr><td>2.9
-</td><td>

Market Related Comments:

The 85 percent availability level may be inadequate in terms of utility market requirements for IGCC plants. The consensus of the EPRI-sponsored Coal Fleet group is that 90 percent availability is an important requirement. The text should include a discussion of any potential availability and reliability differences among the three IGCC technologies studied and between the CO_2 capture and non-capture cases.

</td><td>See comment 6 on guidance sheet.</td></tr>
<tr><td>2.10
-/+</td><td>

Presentation Related Comments:

Exhibits 3-100 and 3-101 (pages 255 and 256), Exhibits 4-48 and 4-49 (pages 413 and 414), and Exhibits 5-26 and 5-27 (pages 487 and 488) should be included in the Executive Summary and briefly discussed, highlighting the point that the relative COE changes only slightly over a wide range of availabilities and fuel prices.

</td><td>Disagree with moving to Exec. Sum., but will add discussion in relevant sections.</td></tr>
<tr><td>2.11
-/+</td><td>The plant costs are stated throughout the report to a precision of four significant figures in $/kW. It should be emphasized that these costs are estimated (albeit consistently) and their accuracy is ±30 percent. This information should be included both in the Executive Summary and Introduction. It would be useful to include error bars on the graphs in the Executive Summary on TPC and COE to illustrate the wide range of these costs and the extent of potential overlap.</td><td>Estimate accuracy appears in Ex Sum, but will add it to the Introduction. Error bars not recommended on a bar chart.
Make sure significant figures make sense. Since accuracy is ± 30%.</td></tr>
<tr><td>2.12</td><td>The royalty allowance included in the cost tables is an arbitrary value and this should be noted</td><td>Explain in cost</td></tr>
</table>

No.	COMMENT	RESPONSE
-	in the title, perhaps as "Arbitrary Royalty Allowance."	methodology section.
2.13 -	The font used on the IGCC drawings is too small to be read clearly. It should be enlarged to the same size as that used on the PC, SCPC, and NGCC drawings.	Font size is the same – should be printed on 11 x 17 paper.
2.14 +	Qualitative comparisons are made throughout the report (i.e., significantly higher, twice as high, etc.). It would be much more useful to include numbers that the reader could use for information purposes.	Will quantify these where appropriate.
2.15 +	**Specific Comments:** Page – Title: "Parsons" is misspelled as "Parons" following Matuszewski.	I suppose we can make this correction.
2.16 +	Page xi: • "Clean Coal Technology" should replace "Clean coal technology." • "cm." should replace "CM."	Will change.
2.17 +	Page xiv: POTW should be added to the list of acronyms.	Will add.
2.18 +	Page 1: • Line 3 – replace "basis" with "manner". • Line 4 – after "current market conditions," add a parenthetical note: "(capital equipment commodities, labor, etc.)." • The word "Reliability" should be inserted after "Availability" in the sixth bullet down from the top of the page. • An additional bullet should be added after the Fuel Prices bullet titled: "Cost of Electricity."	Will make changes.
2.19 +	Page 2: • Add the phrase "but at a significantly higher Cost of Electricity" after the first bullet on the page. • The parenthetical note under Exhibit ES-1 should be amended to include the actual range of carbon capture percentages rather than "less than 95 percent." On Page 8 the range is given as 88.7 to 94.5 percent.	Will make changes.
2.20 +	Page 3: The efficiency titles should include "HHV basis."	Will make change.
2.21	Page 5: The phrase, "with CO_2 capture" should be added after "On average" in the third bullet	Will make change.

No.	COMMENT	RESPONSE
+	from the top of the page.	

No.	COMMENT	RESPONSE
2.22 +	Page 8: The second bullet could be made clearer if reworded as follows: Subcritical PC power plants produced the highest rate of CO_2 emissions per MWh of electricity produced followed in descending order by Supercritical PC, IGCC, and NGCC power plants. The relatively low CO_2 emissions from an NGCC power plant are a function… *(continue with existing text)*.	Will make change (applies to third bullet, not second).
2.23 -/+	Page 8: • In the next-to-last paragraph, the words beginning at the end of line 2 and continuing on line 3, "in kg/mWh," should be deleted. • The value of the third bullet could be enhanced by using a number, instead of "significantly higher," to describe the higher CO_2 emissions that occur with CoP technology.	No to first – the units are relevant to the calculation. Ok to second, even though the numbers appear in tables and text elsewhere.
2.24 +	Page 10: The rows with values for Coal Flowrate and Natural Gas Flowrate should be amended by replacement of the zeroes with n.a.	Will make change
2.25 +	Page 12: • Line 3 – replace "basis" with "manner". • Line 4 – after "current market conditions," add a parenthetical note: "(capital equipment, commodities, labor, etc.)." • The word "Reliability" should be inserted after "Availability" in the sixth bullet down from the top of the page. • An additional bullet should be added after the Fuel Prices bullet titled, "Cost Of Electricity" (These comments also apply to the introductory material in Sections 3 and 4).	Same as 2.17 – will make changes.
2.26 +	Page 13: The second paragraph should note that the Advanced Model F combustion turbine used for all the IGCC cases and the NGCC cases is basically the same machine (with minor modifications of the hot section parts). Its output is 232 MW with syngas and 185 MW with natural gas.	Will add text.
2.27 -	Page 18: Why are the design bases that are based on presumptive values for Hg capture set at 95 percent for IGCC and 90 percent for PC? This difference should be explained.	This was explained in Section 2.4.
2.28 -	Page 19: Exhibit 2-6 – It would be useful to include a column of consistent units for emissions, such as lbs/MWh.	Not feasible – would require an assumed heat rate which is different for each case.

No.	COMMENT	RESPONSE
2.29 +	Page 20: The second paragraph under the heading Mercury ends with the sentence, "The Hg design basis was meant to be a worst case scenario." The reasons for selection of "a worst case scenario" should be explained.	See comment 3 on guidance sheet.
2.30 +	Page 22: In the second paragraph under Cost Estimating Methodology, the first sentence of the second paragraph should be amended to include the parenthetical note (TPC) after Total Plant Cost.	Will make change.
2.31 -	Page 23: The second bullet states that the estimates for PC and NGCC plants are for nth plants and for recent commercial offerings (which are all essentially still first-of-a kind-plants) for IGCC plants. There should be some comments made about the expected reduction in IGCC nth plant costs compared to recent commercial offerings. I don't think the reader would be interested only in what these types of plants are estimated to cost in 2010. There should be a strong interest in what future costs might be. For example, is a 20 percent reduction likely?	Beyond the scope of this study. Need to address the commercial readiness/risk in process contingencies. See comment 7 on guidance sheet.
2.32 -	Page 27: Third paragraph – Is the advanced F-Class design commercially available now? Is there any experience with it on either syngas or hydrogen that can be used to predict O&M costs? If not, the assumptions made should be explicitly stated.	All equipment assumed to be commercially available. Maintenance costs all a % of capital. All equipment is not commercially available…so this must be addressed in contingencies and how capital and O&M costs were determined should be explained.
2.33 +	Page 27: Fourth paragraph – The typical range of reduced firing temperatures for these advanced machines should be explicitly stated.	Will make change assuming data are available.
2.34 +	Page 28: • The conventional and elevated pressures used in ASU plants should be explicitly stated. • The phrase "twice as high" doesn't convey any useful information.	Will provide the relevant numbers.
2.35	Page 29: ASU Basis, first paragraph – The decision to use air integration "for the non-carbon	An explanation is provided.

No.	COMMENT	RESPONSE
-	capture cases only" should be explained.	
2.36 +	Page 33, Third paragraph; last sentence: "contolled" should be replaced by "controlled".	Will make change.
2.37 NETL	Page 38, Last sentence: The reasons why the two-stage Selexol process was chosen for all of the carbon capture cases should be explicitly stated.	It is generally accepted within the industry to utilize a physical solvent for CO_2 capture as compared to a chemical solvent. Selexol is the most commonly used solvent in studies of this type. There was not an exhaustive option comparison performed for this study. Best engineering judgement was used here. Make sure to include this type of technology selection or rationale in the report.
2.38 +	Page 42, Last paragraph: Was the same "proprietary pressure letdown device" used in the designs for all six IGCC cases? Is it the same device that has been used in only the CoP demonstration plant?	Clarification will be added, although this is a very minor detail. What is this device? How important is it to the cost or performance? Clarify.
2.39 +	Page 43: It would aid the reader if performance information for a simple cycle using the design basis turbine was included in Exhibit 3-9. The information in the exhibit indicates that the combined cycle output on natural gas is 280 MW. Previously, it was stated that the simple cycle output was 185 MW. Restating the simple cycle output would help the reader avoid having to search the report to locate that information.	Will re-state the simple cycle output.

No.	COMMENT	RESPONSE
2.40 -	Page 53, Second paragraph: What are the features of the improved GEE process compared to those used at the TECO Polk Power Station IGCC plant? These should be discussed, including potential impacts of these changes on plant reliability.	Beyond the scope of this study.
2.41 +	Page 54, Exhibit 3-13: In the third row of the table, it would be better to use Nominal Unit Output or Nominal Unit Rating rather than Nominal Unit Size. (This same comment applies to similar exhibits elsewhere in the report.)	Will make change.
2.42 +	Page 54: The parenthetical note under Exhibit 3-13 should give the overall CO_2 capture level. (This same comment applies to similar exhibits elsewhere in the report.)	Will make changes.
2.43 +	Page 57, Exhibit 3-16: Is the assumed carbon conversion of 98 percent obtained in single-pass or recycle operation? This seems high for a GEE gasifier based on data from the TECO plant. No equipment for recycling unconverted carbon to the gasifier is included in the plant equipment list.	Recycle of gasification fines maximizes the carbon conversion provided by the vendor on the NYPA study. Equipment is not specified by is included in the costs. Will clarify in text.. Add reference to NYPA.
2.44 -	Page 68: Is the limit on the steam cycle pressure of 1800 psig really due to the pressure rating of the piping, or are the economics of a higher-pressure steam cycle poorer because of higher steam system equipment cost at high pressure?	All of the reasons stated apply. This is a point of optimization that would require support of cooler manufacturers like Alstom and could be the subject of a sensitivity analysis but is beyond the scope of this study.
2.45 +	Page 76: If the GEE gasifier operates at temperatures in excess of 2500 °F, why is the gasifier exit temperature at 2450 °F? This point should be clarified.	It is not a set number and will be fuel dependant and can be varied to support various design specifications. It will be

No.	COMMENT	RESPONSE
		made consistent.
2.46 +	Page 77: How is the fine carbon particulate matter removed?	Will add text to describe particulate control.
2.47 -	Page 89, Exhibit 3-29: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Not necessary and would result in significant needless re-work.
2.48 +	Page 90, Exhibit 3-30: The Royalty Allowance doesn't need two zeroes to the right of the decimal point. It should read 1000 rather than 1000.00 (This same comment applies to similar exhibits elsewhere in the report.)	Will make change.
2.49 -	Page 121, Exhibit 3-44: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals.	Same as 2.46.
2.50	Page 122, Exhibit 3-45: The Royalty Allowance doesn't need two zeroes to the right of the decimal point. It should read 1000 rather than 1000.00. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.47. Check significant figures throughout report.
2.51 -	Page 125, Second paragraph: What are the features of the improved CoP process compared to those used at the Wabash River Repowering IGCC plant? These should be discussed, including the potential impacts of these changes on plant reliability.	Beyond scope of the study. However, if we assumed changes to the gasifier compared to Wabash, these should be listed.
2.52 +	Page 125, Third paragraph: It should be noted in this paragraph that an amine process is used for H_2S removal when CO_2 capture is not practiced.	Will add text.
2.53 +	Page 126, Exhibit 3-47: In the third row of the table, it would be better to use Nominal Unit Output or Nominal Unit Rating rather than Nominal Unit Size. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.40.
2.54 +	Page 126: The parenthetical note under Exhibit 3-47 should give the overall CO_2 capture level. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.41.
2.55 +	Page 127, Point 3 under 3.3.1 Key System Assumptions: The decision to use air integration "for the non-carbon capture cases only" should be explained in more detail. (This same comment applies to similar exhibits elsewhere in the report.)	Was explained on p. 29, but will add text to amplify the discussion.

No.	COMMENT	RESPONSE
		Is it possible to add a reference?
2.56 +	Page 130, Second paragraph; fifth line under Gasifier Background: Replace "gasifies" with "gasified". Please add a comment that indicates that the combustion turbines at the Plaquemine IGCC plant were always co-fired with a minimum of 20 percent of natural gas in the syngas to ensure continuous power output to the petrochemical complex.	Will make changes.
2.57 +	Page 131, Third complete paragraph, beginning with "Two-stage operation": Please explain why, if two stage operation is more efficient and requires about 10 percent less oxygen, the overall efficiency is slightly lower (38.5 percent) for the CoP technology than that calculated for the single-stage GEE process (38.6 percent).	Will add explanation.
2.58 +	Page 131, Fourth complete paragraph: Please change the tense from present to past when describing the Plaquemine unit, which was dismantled in the 1990s. Also, it should be noted that the Wabash River combustion turbine is a GE F class turbine and not an Advanced GE F Class turbine.	Will make changes.
2.59 +	Page 133: The first three sentences of the fourth paragraph should be incorporated into the first paragraph. There is significant overlap between the two paragraphs.	Will make change.
2.60 +	Page 133: The next-to-last sentence in the second paragraph is not clear and should be re-written.	Will re-write sentence.
2.61 -	Page 158, Exhibit 3-59: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.62 +	Page 159, Exhibit 3-60: The Royalty Allowance doesn't need two zeroes to the right of the decimal point. It should read 1000 rather than 1000.00. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.47.
2.63 -	Page 186, Exhibit 3-70: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.64 +	Page 187, Exhibit 3-71: The Royalty Allowance doesn't need two zeroes to the right of the decimal point. It should read 1000 rather than 1000.00. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.47.

No.	COMMENT	RESPONSE
2.65 -	Page 189, Second paragraph: What are the features of the improved Shell process compared to those used at the Buggenum plant? These should be discussed, including potential impacts of these changes on plant reliability.	Beyond the scope of the study.
2.66 +	Page 190, Exhibit 3-73: In the third row of the table, it would be better to use Nominal Unit Output or Nominal Unit Rating rather than Nominal Unit Size. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.40.
2.67 +	Page 190: The parenthetical note under Exhibit 3-73 should give the overall CO_2 capture level. (This same comment applies to similar exhibits elsewhere in the report.)	Same as previous.
2.68 +	Page 191, Point 3 under 3.4.1, Key System Assumptions: The decision to use air integration "for the non-carbon capture cases only" should be explained.	Same as previous.
2.69 +	Page 195, Gasifier Background: The tense used in the first paragraph should be changed from present to past to reflect the fact that the SCGP-1 unit at Deer Park, TX was dismantled. I believe that Shell now offers a design that reflects both the Plaquemine and Puertollano plant experience of Krupp-Koppers. The current situation should be summarized.	Will update Deer Park write-up.
2.70 +	Page 197: The third paragraph is different from that used as part of the descriptions of the GEE and CoP IGCC plants. The same paragraph should be used in all three cases or not at all.	Will make consistent.
2.71 -	Page 222, Exhibit 3-8: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.72 +	Page 223, Exhibit 3-86: The Royalty Allowance doesn't need two zeroes to the right of the decimal point. It should read 1000 rather than 1000.00 (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.47.
2.73 -	Page 225: Was Shell asked if water injection could be utilized instead of syngas recycle to quench the gasifier effluent, so that the amount of steam diverted to the shift reactor could be reduced? This would increase the power output of the steam turbine, resulting in higher efficiency.	This configuration was not considered for this study. See comment 10 on guidance sheet.
2.74 -	Page 250, Exhibit 3-95: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.75	Page 251, Exhibit 3-97: The Royalty Allowance doesn't need two zeroes to the right of the	Same as 2.47.

No.	COMMENT	RESPONSE
+	decimal point. It should read 1000 rather than 1000.00. (This same comment applies to similar exhibits elsewhere in the report.)	
2.76 -	Page 255, Exhibit 3-100: The coal price used for these curves should be noted on the exhibit. This exhibit should be moved to the Executive Summary.	Coal price in figure on next page. No to move to Exec. Sum.
2.77 -	Page 256, Exhibit 3-101: The capacity factor used for these curves should be noted on the exhibit. This exhibit should be moved to the Executive Summary.	CF in figure on previous page. No to move to Exec. Sum.
2.78 ?	Pages 258-281: These pages of cost estimating detail may provide important insights into the major investment differences among the GEE, CoP, and Shell technologies. These investment differences should be analyzed and commented on. For example, why is the CoP investment significantly lower (~$140/kW) than GEE or Texaco. Is it the gasifier vessel, heat recovery system, solids letdown system, gasifier structure, or something else? That detailed information should be summarized and included in the Executive Summary. It should not be left to the reader to come to his or her own conclusions about why there are significantly lower investment requirement for the CoP process. It would also be important to add information on how the estimated cost of the gasifiers was obtained. After all, each is a new design concept compared with the existing demonstration plants. Did Parsons develop this information independently or depend on the three process licensors to supply estimated cost information for the gasifiers?	Add Amick's info to explain lower CoP cost. Should add more explanation on costing key components of the systems like the gasifier and turbine. See comment 9 on guidance sheet.
2.79 -	Page 284, Last sentence on page: What is the design availability?	CF is 85% - availability is not relevant. See comment 6 on guidance sheet.
2.80 +	Page 288, First paragraph: What is the overall sulfur removal if the concentration of SO_2 in the flue gas is 10 ppm?	Clarification will be provided – FGD is 98%; Econamine system provides polishing step to reduce to 10 ppm.
2.81 +	Page 289, Second complete paragraph on page: What is the flue gas exhaust temperature?	Will add flue gas exhaust temps.
2.82 -	Page 325, Exhibits 4-13 & 3-85: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost.	Same as 2.46.

No.	COMMENT	RESPONSE
	The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	
2.83 ?	Page 326, Exhibit 4-14: The same project contingency, 10.9 percent, is used in Cases 1 and 2 for GEE IGCC technology with and without CO_2 capture, respectively. In Case 9, PC technology without CO_2 capture, a project contingency of 8.9 percent is used, reflecting, I assume, the greater maturity of the PC plant technology relative to IGCC. In the comparable PC Case 10 with CO_2 removal, a higher project contingency of 10 percent is used. Why was the project contingency raised for PC Case 10 with CO_2 capture and not for Case 2 with CO_2 capture? (The same comment applies to Cases 11 and 12.)	See comment 7 on guidance sheet.
2.84 -	Page 355, First paragraph: What is the design availability for Cases 9 and 10?	See 2.78.
2.85 -	Page 381, Exhibit 4-38: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.86 -	Page 413, Exhibit 4-48: The coal price used for these curves should be noted on the exhibit. This exhibit should be moved to the Executive Summary.	Same as 2.75.
2.87 -	Page 414, Exhibit 4-49: The capacity factor used for these curves should be noted on the exhibit. This exhibit should be moved to the Executive Summary.	Same as 2.76.
2.88 -	Page 459, Exhibit 5-12: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.89 -	Page 482, Exhibit 5-22: Information in the final column to the right is presented in a confusing manner with totals and subtotals placed in the same column under Total Plant Cost. The furthest right column should be split into multiple columns that clearly differentiate between totals and subtotals. (This same comment applies to similar exhibits elsewhere in the report.)	Same as 2.46.
2.90 -	Page 484, Exhibit 5-24: The same 100 acre land area was proposed for the NGCC plant with CO_2 capture as was proposed for the plant without CO_2 capture. Should extra land be proposed for the CO_2 capture and pressurization system?	100 acres is more than enough in both cases.
2.91	Page 487, Figure 5-26: The natural gas price used for these curves should be noted on the	Same as 2.75.

No.	COMMENT	RESPONSE
-	exhibit. This exhibit should be moved to the Executive Summary.	
2.92 -	Page 488, Exhibit 5-27: The capacity factor used for these curves should be noted on the exhibit. This exhibit should be moved to the Executive Summary.	Same as 2.76.

No.	COMMENT	RESPONSE
3. Comments – Set 3 [JMW]		
3.1	**General Comments:** I have found the report to be well written, with the text, tables, and figures more than adequate to convey the information contained in the analyses that are the basis for the report. The technical descriptions are concise, but more than sufficient to describe the systems that make-up the power system being analyzed. The methodology used to report performance and cost information is consistent with historical reporting, which makes it compatible with other data currently being considered for evaluating power systems.	
3.2 ?	The Executive Summary does an adequate job of reporting the results of the analyses and contrasts the major differences of the various technologies. However, neither the Executive Summary nor the detailed texts provide comparisons that contrast the cost and performance differences for different systems within the same technology. For example, a significant capital and LCOE difference is reported among COP E-Gas IGGCC without CO_2 capture ($1576/kW, $49.4MWh), GEE ($1,730, $54.7/MWh), and Shell ($1,770,$53.8MWh) IGCC. This difference is not discussed or explained. It is important for the reader to understand this difference. More importantly, if this difference is real, the results of this analysis would have the reader believe that an IGCC system offered for commercial operation in 2010 produces a lower LCOE ($49.4/MWh) than either a subcritical PC unit ($49.9) or a supercritical PC unit ($49.9).	Response in progress (this is the same issue raised in 2.77 and concerns the capital cost of the CoP IGCC. The same issue is covered in 3.3 and 3.4 below. Same comment as 2.78
3.3 ?	With regard to whether the results are reasonable and credible, I am concerned that the IGGC versus PC results, as described in the preceding paragraph, bring into question the results of the cost analysis for the CoP E-Gas IGCC-based systems. With the exception of the E-gas results, I believe that the IGCC versus PC versus NGCC results with and without CO_2 capture appear reasonable and credible, based on previous analysis done for DOE by other entities such as EPRI and on recent private work done for the FutureGen Alliance. There is a widespread view held by government and industry that IGCC is 10 to 30 percent more costly than PC technologies that could be placed in service by 2010, and that IGCC produces higher LCOE than PC technology.	See 3.2. See comments 8 and 9 on guidance sheet.

No.	COMMENT	RESPONSE
	This view is supported by many recent references: • "IGCC with eastern coal is $5/MWh higher than SCPC and $7/MWh with western coal," Public Service Commission of Wisconsin, IGCC Draft report, June 2006; • "IGCC capital costs (without CO_2 capture) are about 20 percent to 30 percent higher than PC costs," Ontario Power Authority, Report to Minister, December 2005; • "IGCC currently – 20 percent capital cost premium to SCPC," Moving IGCC Forward, GE Energy, July 2005; • "Industry analysts estimate capital costs for a 500-600MW IGCC are 10-20 percent higher than conventional PC," CINERGY Corp., April 2005; • TPC/LCOE ($2003) for subcritical PC, SCPC, and E-gas IGCC without and with a spare gasifier: $1,230/$46.5/MWh; $1,290/KW/$46.6/MWh; $1,250/KW/$47/2/ MWH; and $1,350/$49.9/MWh," EPRI, July 2004.	
3.4	Representatives of the CoP E-Gas technology in October 2005 provided comparative E-Gas IGCC performance and cost information for various domestic fuels (Breton et al., GTC Meeting, October 2005). That paper estimated that overnight EPC capital costs, including contractor profit and contingencies, ranged from $1,350/KW to $1,650/KW ($2005). The source of this information was referenced as a report done for NETL, "Gasification Plant Cost and Performance Optimization, Bechtel, Global Energy, and NEXANT," September 2003. That report, which was based on the E-Gas Technology, estimates that the capital cost to rebuild a Wabash River type IGCC would be $1,680/KW ($Mid2000), while a Current Coal IGCC, such as that described in this report, would have a capital cost of $1,318/KW ($Mid2000). Assuming a general inflation rate for this type of technology of 3 percent/year, which is conservative based on recent quotes for materials, the current E-Gas IGCC TPC cost would be $1,551/KW, which is approximately 10 percent higher than the $1,417/KW TPC cost predicted in this report and is in line with the projected costs for GEE and Shell IGCC technologies.	See 3.2.
3.5 ?	My recommendation is that the authors re-evaluate the performance and cost estimates for the E-Gas IGCC Technology and, in the report, explain the differences, if any, between the capital costs and LCOE for the three IGCC technologies. If the lower cost for the E-Gas IGCC is real, the authors should explain somewhere in the report the differences between these results and	See comment 3.2

No.	COMMENT	RESPONSE
	those of recent studies which showed significantly different results. I caution NETL on the importance of getting these numbers right because of their implications for the DOE IGCC RD&D programs, and the IGCC tax credits and other incentives being sought by industry to advance the IGCC technology.	
3.6 -	**Specific Comments:** Page 1: "The objective of this report is to present performance and cost data for fossil energy power systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants, in a consistent technical and economic basis that accurately reflects current market conditions for plants starting operation in 2010." Comment: Other than the NGCC units, it would be very unlikely that either an IGCC or PC unit could be placed in service by 2010. Perhaps it would be better to describe the time frame for service as 2012 to 2015 for the non-CO_2 capture commercial applications and beyond 2015 for the CO_2 capture installations.	Study assumption was that all technologies are commercially available to support a 2010 start-up. No changes will be made to the time frame.
3.7 -	Page 16, Exhibit 2-3 Design Coal Specifications: Comment: The Illinois # 6 design coal specification selected for this report represents a very high quality Illinois Basin steam coal and does not represent the majority of production from the basin. Take no action in this report, but in future studies it may be appropriate to select a broader coal specification.	Coal spec not likely to be changed.
3.8 +	Page 17, Fuel cost: Comment: The fuel cost assumptions seem reasonable in the current, very fluid marketplace.	We concur.
3.9 NETL	Page 20: "Further, it was assumed that all of the coal mercury enters the gas phase and that no co-benefit mercury capture occurs in any of the other gas treating equipment. Thus, the carbon beds in the case of IGCC and carbon injection in the case of PC were designed to treat all of the mercury in the gas stream. This is especially conservative in the PC cases where it is known that a large percentage of the Hg will be collected in the FGD unit, particularly with an upstream SCR to oxidize elemental mercury. The Hg design basis was meant to be a worst case scenario."	See comment 3 in guidance sheet.

No.	COMMENT	RESPONSE
	Comment: By giving no allowance for mercury capture in the FGD system, the report penalizes PC technology only. The authors should assume a reasonable amount of capture for the PC applications. Sufficient data exists within DOE and EPA for doing this. At a minimum, if this conservative assumption is retained, the authors should provide results of a sensitivity analysis that brackets the capital and LCOE costs of this assumption.	
3.10 -	Page 23: "The estimates represent commercial technology plants or nth plants for PC and NGCC and recent limited commercial offerings for IGCC." Comment: The performance and cost estimates for IGCC must reflect the uncertainty of the technology today for 2010 start-up because there has been a limited number of commercial offerings and no offerings or operating experience in a carbon capture mode. The same project and process contingencies for IGCC, PC, and NGCC technologies cannot be justified. The authors need to review and revise these assumptions in this light.	No process contingencies were included based on assumption that all technologies would be commercial to support a 2010 start-up. The project contingencies do vary from case to case. See comment 7 on guidance sheet.
3.11 -	Page 23: "Project contingencies were added to the EPC capital accounts to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. The contingencies represent costs that are expected to occur. Each bare erected cost (BEC) account was evaluated against the level of estimate detail and field experience to define project contingency. Process contingencies were not applied since each process is assumed to be commercial at the time of construction." Comment: This assumption cannot be supported for IGCC technology that is to be placed in service by 2010 or any technology that will include CO_2 capture systems. There is limited operating experience with IGCC technology without CO_2 capture and no experience with integrating the operation of any coal-based power generation technologies capturing CO_2 at the scale envisioned in this report. Reasonable process contingencies for the gasifier island (5 percent) and the slag/ash removal systems (3-5 percent) should be added for the non-CO_2 capture cases. In addition to these contingencies, reasonable process contingencies (5-10 percent) should be added to the acid gas, CO_2 capture, and H_2 combustion turbine cost estimates. With an almost total lack of operating experience, it is not supportable in the 2010 timeframe to project these cost categories without process cost contingencies. These	Nonetheless, this was the assumption made and applied consistently throughout. We do not plan to change at this point in the study. Will be changed according to OSAP guidance sheet.

No.	COMMENT	RESPONSE
	contingencies should apply to PC and NGCC technologies where CO_2 capture is to occur.	

No.	COMMENT	RESPONSE
3.12 NETL	Pages 24 - 26: • "The operating and maintenance expenses and consumable costs were developed on a quantitative basis. • "Operating labor cost was determined on the basis of the number of operators required. • "Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. • "Cost of consumables, including fuel, were determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours. • "Byproduct credits for commodities such as gypsum, sulfur and emissions were not considered due to the variable marketability. However, neither were the technologies penalized with a disposal cost for the byproducts." Comment: These statements appear to be reasonable but there is no discussion of where the IGCC quantitative factors came from or how they were derived. Are the O&M numbers taken from Tampa or from Wabash River operating experience? Do the three IGCC technologies have the same O&M costs, since there are major component differences? The authors should provide a discussion of how the operating labor, maintenance labor, A&G, maintenance materials, and consumables factors were developed; and should provide the values.	This information is available in the cost detail sheets – number of operators, labor rates, maintenance labor costs, maintenance materials costs, consumable costs, etc. Is that adequate? The report must list not only the values used….but should discuss how these values were estimated. Please review the O&M costs for the IGCC cases. Does it make sense to base O&M off of capital cost when the gasification configurations contain basically the same unit operations. Are they really that different in complexity to need different laborers, etc?.

No.	COMMENT	RESPONSE
4. Comments – Set 4 [WBJS]		
4.1 -	**General Comments:** The report would benefit greatly from the addition of a section that more clearly defines the purpose of the report, including a summary of its intended use by DOE and the coal program's stakeholders.	Purpose and use are stated in the Exec Sum. Adding a section to repeat this does not seem warranted.
4.2 -	The Executive Summary would be strengthened by the inclusion of a description of the rationale for selecting the technologies for comparison. Specifically, the decision to exclude ultra-supercritical PC-fired boilers and fluidized bed combustion should be explained. Further, the criteria for selection of "advanced F" technology combustion turbines in lieu of "H" technology should be discussed.	This logic (or illogic) could be extended to many sections of the report and does not seem warranted.
4.3 -	The report could be enhanced by the addition of a section comparing FBC technology to PC and IGCC technology, and evaluating technical, environmental, and economic differences.	Beyond the scope of this study.
4.4 -	Some of the references used throughout the report appear outdated (e.g., Reference 14 is dated 12/87; Reference 19 is dated 12/93; Reference 24 is dated 10/93; and Reference 27 is dated 1994).	Rhetorical comment – no reply required.
4.5 -	The estimated level of accuracy of ± 30 percent is too high and tends to invalidate the report's conclusions. The EPRI TAG report typically presents levels of accuracy in the ± 10 percent range for mature, commercially available technologies.	Level of accuracy is dependent on the amount of design/analysis done not on the maturity of the technology.

No.	COMMENT	RESPONSE
4.6 -	The list of references includes seven GE reports but identifies no other combustion turbine vendors' reports. I suggest that other combustion turbine suppliers' data and information be included in the report.	GE advanced F-class turbine data were used in the simulations. Listing other CT data would not serve a useful purpose. To show that we are unbiased, we should also reference sources of Siemens performance estimates (even if only on natural gas) to indicate that what we used, although based on GE data, is representative of an advanced F turbine. If their operation on natural gas is similar, it is reasonable to assume they could both operate at similar efficiencies with syngas.
4.7 -	Although the GE 7FB combustion turbine has been used for the NGCC and IGCC cases, it has not been identified and the rationale for selection is not discussed. I suggest the report specifically identify the CT make and rationale for selection.	We were specifically requested not to mention GE by name.
4.8 +	The report could be improved by the addition to the basic assumptions of a discussion of sensitivities (e.g., the impact of changing fuel cost relative to the report's conclusions should be included).	Fuel cost and CF sensitivities are included. The discussion will be expanded per comment 2.9.

No.	COMMENT	RESPONSE
4.9 -	A web-based search for similar evaluations yielded numerous technology comparisons that have been performed by a variety of organizations in the past five years (see *#4.84*). The addition of a section that compares the conclusions of these reports to the conclusions reached in the subject report would be beneficial (see *#4.15*). Specifically, a comparison to the data/conclusions presented in the most recent EPRI TAG Report is strongly recommended for inclusion.	Comparisons with other studies were intentionally avoided. Invariably such comparisons are "apples-to- oranges."
4.10 -	A Technical Report entitled, "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal" (dated 12/2000; prepared by Parsons Energy and Chemicals Group, Inc.; and sponsored by EPRI, DOE HQ, and DOE NETL) analyzes 12 technology cases and describes an additional 6 cases. However, very few of the 18 total technology cases selected for review in the 2000 report are comparable to the technology cases selected for inclusion in the 2006 report. Since both reports were prepared by Parsons, several questions result: • Why is the 2000 report not referenced in the 2006 report? • Why are the technologies selected for comparison in the 2006 report so different from those evaluated in the 2000 report? If the technology scorecard has changed so dramatically over the past 5-years, is it likely to change significantly in the next 5 years, and if so, can the conclusions in the 2006 Report be considered valid for future decision making.	We were directed not to reference the previous report. The technologies chosen represent the most likely candidates to be built in today's market. It's nearly impossible to predict how that will change in the future, and doing so is beyond the scope of this study.
4.11 -	The method of data presentation used in the 2000 report is superior to that in the 2006 report. The data summary tables in the 2000 report are more concise, more informative, and are easier to read and comprehend.	We believe the data presentation in the current report is very readable and understandable.
4.12 -	Too much technology-related descriptive detail is presented in the 2006 report. Where the 2000 report presents a system description in 5 pages, the 2006 report contains 25 pages. Suggest deleting this detail, or relegating it to an appendix.	A feature of this report is that each case can be removed from the report and stand on its own, thus the repetitive and lengthy descriptions.

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td>4.13
-</td><td>I suggest moving the estimating methodology to an appendix and combining it with the detailed cost breakdowns for each technology. Summary tables for TPC Cost, Annual Production Cost, and Levelized Results should be prepared for each technology.</td><td>Disagree with moving cost methodology to an appendix. Summary tables and figures are contained in the Exec. Sum.</td></tr>
<tr><td>4.14
-</td><td>A report of this nature invariably leads to the question: Which technology wins? In this case, the winner appears to be IGCC and this supports DOE's selection as the cornerstone of FutureGen. Two questions result:

• Is DOE prepared for criticism of this approach, particularly since the technologies selected for evaluation are somewhat limited (e.g., FBC, USC, and nuclear have been excluded)?
• If DOE is seen as actively supporting one technology over another, what are the ramifications?</td><td>2/3 IGCC cases have higher COE than PC cases, so not clear that IGCC "wins." (See comment 5.4) Of the 10 peer reviewers we received no criticism for excluding FBC, USC or nuclear. The disclaimer absolves DOE of favoritism.</td></tr>
<tr><td>4.15</td><td>The following tabulation was prepared to verify the relative accuracy of the data presented in the 2006 report compared to other existing data sources (see #4.84):

Data Comparison
<table>
<tr><th>Parameter</th><th>2006 Report</th><th>Range of Data in Other Sources (2000 Report, see #4.84)</th></tr>
<tr><td>IGCC without Capture</td><td></td><td></td></tr>
<tr><td>• Efficiency, %</td><td>38.5 to 40.3</td><td>37.5 to 45 (43.1)</td></tr>
<tr><td>• Heat Rate, Btu/kWh</td><td>8466 to 8870</td><td>7584 to 9960 (7915)</td></tr>
<tr><td>• Capital Cost, $/kW</td><td>1417 to 1593</td><td>1100 to 1830 (1420)</td></tr>
<tr><td>• Cost of Electricity (mills/kWh)</td><td>49.4 to 65.1</td><td>37 to 70 (52.4)</td></tr>
<tr><td>• CO_2 Emissions, kg/MWh</td><td>765 to 802</td><td>682 to 846</td></tr>
<tr><td>IGCC with Capture</td><td></td><td></td></tr>
<tr><td>• Efficiency, %</td><td>30.6 to 32.6</td><td>(37)</td></tr>
</table></td><td>Comparison with other studies was intentionally avoided.
See comment 8 in guidance sheet.</td></tr>
</table>

No.	COMMENT	RESPONSE

• Heat Rate, Btu/kWh	10463 to 11156	(9226)
• Capital Cost, $/kW	1861 to 2252	1402 to 2828 (1844)
• Cost of Electricity (mills/kWh)	63.6 to 89.9	54 to 83.9 (65.7)

Data Comparison (cont'd)

Parameter	**2006 Report**	**Range of Data in Other Sources (2000** Report, *see #4.84*)
NGCC without capture		
• Efficiency, %	50.6	52 (50.1)
• Heat Rate, Btu/kWh	6737	6541 to 7200 (6811)
• Capital Cost, $/kW	507	447 to 1000 (549)
• Cost of Electricity (mills/kWh)	63.9 to 67.5*	22 to 45 (34.2)
NGCC with Capture		
• Efficiency, %	43.4	42.8 (39.2)
• Heat Rate, Btu/kWh	7857	No data (8698)
• Capital Cost, $/kW	884	820 to 2020 (1099)
• Cost of Electricity (mills/kWh)	83.7 to 89.9*	32 to 62.1(57.9)
PC w/o Capture		
• Efficiency, %	36.3 to 38.5	29.9 to 43 (40.5)
• Heat Rate, Btu/kWh	8857 to 9389	8600 to 10333 (8421)
• Capital Cost, $/kW	1323 to 1355	1100 to 1644 (1281)
• Cost of Electricity (mills/kWh)	49.7 to 59.3	26.7 to 52 (51.5)
PC with Capture		
• Efficiency, %	23.9 to 26.9*	29.9 to 30.2 (28.9)
• Heat Rate, Btu/kWh	12662 to 14276*	No data (11816)
• Capital Cost, $/kW	2626 to 2635*	1940 to 2585 (2219)
• Cost of Electricity	83.5 to 102.6	56.3 to 148 (85.6)

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td></td><td>
<table>
<tr><td>(mills/kWh)</td><td></td><td></td></tr>
</table>

Based on the above comparison, the following potential areas of concern are highlighted by asterisk:

• The LCOEs for both NGCC cases are well out of the range of values found in other literature sources, including the 2000 report.
• In general, the data presented for the PC with capture case penalizes this case significantly more than other literature sources.
</td><td>This could have something to do with the price of natural gas.

In what ways?</td></tr>
<tr><td>4.16
-</td><td>
Since DOE was involved in the preparation of both the 2000 and 2006 reports, a comparison of results was made to determine consistency:

Results Comparison
<table>
<tr><th>2000 Report</th><th>2006 Report</th></tr>
<tr><td>Without CO_2 removal, COEs are very similar for both the IGCC and PC, and show a break-even with the COE of an NGCC at a natural gas price of $4.9/Mbtu-HHV.</td><td>The LCOE for non-CO_2 capture subcritical and supercritical PC cases is 6 percent less than the average for IGCC and 23 percent less than NGCC. The NGCC non-capture LCOE is the highest of the three technologies because of the high cost of natural gas assumed for this study ($7.46/Mbtu).</td></tr>
<tr><td>If CO_2 removal is required for new fossil fuel power plants and, if coal stays at $1.18/GJ, NGCC plants with CO_2 capture offer the lowest COE up to a natural gas price of $4.0/Mbtu. Above $4.0/Mbtu, IGCC plants with CO_2 removal have a lower COE than NGCC plants.</td><td>When CO_2 capture is added, the LCOE for IGCC averages 19 percent lower than PC and 18 percent lower than NGCC.</td></tr>
</table>
</td><td>Again, comparisons were intentionally avoided.</td></tr>
</table>

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td></td><td>
<table>
<tr><td>IGCC plants would have a COE ~20 percent lower than PC plants if both were designed for CO_2 removal.</td><td>When CO_2 capture is added, the LCOE for IGCC averages 19 percent lower than PC and 18 percent lower than NGCC.</td></tr>
</table>

Results Comparison (cont'd)
<table>
<tr><th>2000 Report</th><th>2006 Report</th></tr>
<tr><td>The cost of CO_2 emissions avoided with IGCC was markedly less than that of NGCC or USC PC.</td><td>The results show IGCC to be the most cost effective option for carbon capture.</td></tr>
<tr><td>Adjustments normalizing the CO_2 removal cases to the same emissions of CO_2/kWh or taking into account the size of the plant do not significantly alter the above conclusions.</td><td>Not discussed.</td></tr>
</table>

Based on this review, a sensitivity evaluation associated with fuel cost is recommended. Specifically, the cost at which IGCC with CO_2 capture becomes more cost effective when compared to NGCC with carbon capture should be identified (expected to be between $4.9 and $7.46/Mbtu).
</td><td></td></tr>
<tr><td>4.17
+</td><td>Specific Comments:

Cover: Michael Matuszewski, "Parons" should be "Parsons" (typo).</td><td>Duplicate comment, see #Error! Reference source not found.</td></tr>
<tr><td>4.18
+</td><td>• TOC, page i: Sections 2.1 through 2.6 should be bolded for consistency.
• TOC, page i: Section 2.4; capitalize "t" in "targets" for consistency.
• TOC, page ii: Sections 4.2 and 4.3 should be bolded for consistency.
• TOC, pg. iii: Sections 4.4, 4.5, 5, 5.1, 5.2, 5.3, 5.4, and 6 should be bolded for consistency.
• List of A&A, page xii: The "e" in "equivalent" should be capitalized for consistency.</td><td>Will make changes.</td></tr>
<tr><td>4.19
+/-</td><td>Executive Summary: The basis for selection of the technologies chosen should be clearly defined. Further, the basis for exclusion of technologies (FBC, USC, "H" technology) should be added.</td><td>Will discuss basis for selection of technologies, but not exclusion of technologies.</td></tr>
</table>

No.	COMMENT	RESPONSE
4.20 +	*Executive Summary*, page 1: The basis for selection of the timeframe 2010 should be clearly stated and discussed.	Will discuss.
4.21 +/-	*Executive Summary*, page 1: The reviewer suggests re-ordering and expanding the selection factors as follows: • Capital and operating costs • Efficiency (as it effects costs) • Reliability, availability, and maintenance • Flexibility (feedstock and products) • Environmental considerations (emissions and effluents) • Environmental regulations (future changes) – external factor • Fuel prices – external factor • Public support and acceptance – external factor A brief discussion of each factor is needed.	Will add additional items, but discussion should not be necessary.
4.22 +	*Executive Summary*, page 1: The reference to 12 different configurations should be expanded to explain that 14 cases were considered, but that 2 cases are included in Volume 2. Alternatively, all discussion of these 2 additional cases should be eliminated from Volume 1 (recommended approach).	Will explain that 14 cases were run but two were moved to Volume 2. Eliminate SNG cases from discussion in volume 1.
4.23 -	*Executive Summary*, page 1: The combustion turbines selected for evaluation in IGCC and NGCC configurations should be identified and the rationale for selection should be addressed.	Reference to GE was to be avoided – hence advanced F class turbine.
4.24 -	*Executive Summary*, page 1: The sensitivity of the study to the selected coal cost should be addressed.	This is done in subsequent figures.
4.25 -	*Executive Summary*, page 2: The output (MWe) of each case should be added to Exhibit ES-1. The rationale for differences in output between cases should be discussed.	Output is in Exhibit ES-7. Reason for output difference is discussed in other places.
4.26 -	*Executive Summary*, page 2, third bullet: Clarify that IGCC's efficiency over PC increases for both subcritical and supercritical cases for CO_2 capture.	This is evident from the current text.

No.	COMMENT	RESPONSE
4.27 -	*Executive Summary*, page 3: Consider changing the graphical presentation of data to tabular.	Personal preference – others preferred more graphics. Data is in tabular form in ES-7.
4.28 +	*Executive Summary*, page 3: Change "CO2" to CO_2" (typo).	Will change.
4.29 +	*Executive Summary*, page 3: The omission of Cases 7 & 8 requires notation.	Same as 4.20 – will add text. Consider eliminating numbering scheme and go with shorthand case names so that adding or subtracting cases does not impact numerical order.
4.30 -	*Executive Summary*, page 4: See comments *#4.23*, *4.24*, and *4.25*, above.	See 4.21, 4.22 and 4.23 above.
4.31 -	*Executive Summary*, page 5, first paragraph: Change "all of the elements" to "the following elements", as some elements are not included (e.g., emissions offsets, water, wastewater, byproducts).	It's ok as stated.
4.32 ?	*Executive Summary*, page 5: Does the engineering cost include the engineer's contingency, risk, and fee?	Response in progress. See comment 7 in guidance list which asks that contingencies be handled differently and much more explicitly.
4.33 -	*Executive Summary*, page 5: A level of accuracy of ± 30 percent appears too high to be meaningful. The EPRI TAG report typically presents level of accuracy in the ± 10 percent range or less for mature, commercially available technologies.	Same as comment 4.5.

No.	COMMENT	RESPONSE
4.34 -	*Executive Summary*, page 5: The statement that, "All cases were analyzed on a consistent basis using a consistent set of assumptions and analytical tools" appears misleading considering the fact that the technologies were not evaluated on a consistent output basis.	The differences in net output were explained – doesn't negate the statement. To take advantage of the economies of scale for PC plants, OSAP determined that the scale for PC cases could be an unfair advantage to that technology and therefore the current cases should be scaled up to 750 -800MW which appears to be most often cited size for proposed new power plants. Consult new power plant tracking data base on NETL's website to determine most representative PC size.
4.35 -	*Executive Summary*, page 5: The rationale for evaluating LCOE at two different capacity factors should be explained.	Not necessary.
4.36 -	*Executive Summary*, page 5: The conclusions drawn from the 85 percent capacity factor should be addressed for the 65 percent capacity factor.	Not necessary – 85% was study assumption, 65% shown for comparison purposes. See comment 6 in guidance document

No.	COMMENT	RESPONSE
4.37 -	*Executive Summary*, page 5: Since some of the conclusions are tied to fuel assumptions, sensitivities should be performed to validate the conclusions if fuel costs vary from those assumed.	Done in subsequent figures.
4.38 -	*Executive Summary*, pages 6 and 7: See comments *#4.23*, *4.24*, and *4.25*, above.	See responses to 4.21, 4.22 and 4.23 above.
4.39 +	*Executive Summary*, page 8: The statement that, "Every case was configured to produce the same low level of air emissions so that the cases could be compared on an equal design basis" needs to be clarified in light of the prior BACT-related statement.	Will clarify – same BACT technologies applied in each case, but resulting emissions were not equal. See comment 3 in guidance document.
4.40 -	*Executive Summary*, page 9: See comments *#4.23*, *4.24*, and *4.25*, above.	See responses to 4.21, 4.22 and 4.23 above.
4.41 -	*Executive Summary*, page 10: The reviewer suggests simplifying this data to only present key data and to re-orient the format to vertical. More than one table may be required.	Not necessary.
4.42 -	*Executive Summary*, page 11: The reviewer suggests adding a footnote to explain that the emissions are based on differing BACT requirements. A sensitivity to the 65 percent capacity factor should also be included.	See comment 4.37. Discussion of 65% CF results not warranted.
4.43 +	*Introduction*, page 12: The paragraph beginning "Twelve different…" should be reworked, as it is not clear that there are actually 14 cases and that cases 7 & 8 are included in the 14, as opposed to being included in the 12.	Will modify discussion.
4.44 -	*Introduction*, page 12: The second paragraph under **GENERATING UNIT CONFIGURATIONS** needs to be reconsidered. Since the output of the PC cases has been maximized to offset losses associated with carbon capture, couldn't the combined cycle output also be maximized by increasing steam or nitrogen injection? If this approach is not feasible due to fuel flow or other constraints, then these factors need to be addressed. It would appear that the CC cases are being penalized unfairly. Further, a consistent output approach to economic evaluation may be more appropriate.	Not feasible in IGCC and NGCC cases as explained in the report. (See comment 5.13)
4.45 +	*Introduction*, page 12: In the last full sentence on the page, add "combined cycle" between "overall" and "gross."	Will make change.

No.	COMMENT	RESPONSE
4.46 -	*Introduction*, page 13: Reconsider the last paragraph in light of comment *#4.40*, above.	See 4.42 above.
4.47 -	*Site Characteristics*, page 15, Exhibit 2-2: The site acreage appears excessive for all technologies.	It was applied consistently in the study. This is true, but some rationale for why this acreage was selected should be included (is it to allow enough room for trains to do a loop/turnaround?
4.48	*Site Characteristics*, page 15, Exhibit 2-2: The exclusion of wastewater quantities and quality from the analysis is questionable.	See comment 5 in guidance document.
4.49 -	*Site Characteristics*, page 15, Exhibit 2-2: Assumptions regarding fuel source/location, and water/wastewater location (property boundary?) should be added to the table.	Fuel cost is a delivered cost so source/location is not relevant. Report states water discharge through permitted outfall.
4.50 -	*Site Characteristics*, page 15, Exhibit 2-2: Assumptions regarding indoor vs. outdoor enclosures should be addressed, particularly for NGCC.	Excessive detail.
4.51 -	*Site Characteristics*, page 15: Sensitivities among technologies associated with the design parameters not quantified should be discussed.	Excessive detail – beyond the scope of the study.
4.52 NETL	*Coal Characteristics*, page 16: The rationale for selection of Illinois #6 should be addressed. Performance/cost sensitivities related to this selection should also be addressed.	NETL guidelines?
4.53 +	*Coal Characteristics*, page 16: Define AR (as received) in a footnote to Exhibit 2-3.	Will add although it's in the acronym list. AR is not convention…so replace with "as rec'd" or spell out.

No.	COMMENT	RESPONSE
4.54 ?	*Natural Gas Characteristics*, page 17: See comment *#4.48*, above.	Presumably this meant comment 47 above in which case the response is the same.
4.55 ?	*Environmental Targets*, page 18: The BACT discussion needs more amplification. How were BACT levels determined? By review of EPA Clearinghouse data? CFR references should be included.	Response in progress. See comment 3 in guidance document. Should reference recent sources for state emission requirements (see B. Schimmoller)
4.56 +	*Environmental Targets*, page 18: 40CFR60, Subpart KKKK should be discussed for the NGCC cases.	Presumably this meant comment 47 above in which case the response is the same.
4.57 -	*Environmental Targets*, page 18, Exhibit 2-5: The acronyms need to be defined.	Response in progress.
4.58 +	*Environmental Targets*, page 19: The discussion of LAER does not reach a conclusion.	Presumably this meant comment 47 above in which case the response is the same.
4.59 +	*Environmental Targets*, page 19: Exhibit 2-6 does not apply to the NGCC cases. Suggest expansion to include 40CFR60, Subpart KKKK. Further, if liquid fuel is assumed to be used for start-up, the applicable regulations need to be addressed (see NGCC equipment list).	Response in progress. Identify whether this is applicable…and also state whether liquid fuel startup was considered/included in this analysis.
4.60 -	*Raw Water Usage*, page 21: In the third paragraph, the sensitivity of water usage to fuel source should be discussed.	Presumably this meant comment 47 above in which case the response is the same.

No.	COMMENT	RESPONSE
4.61 -	*Cost Estimating Methodology*, page 22: Since the EPRI TAG report is considered to be an industry standard, and since the 2000 report used economic data supplied by EPRI, the reviewer suggests that the economic assumptions used in the 2006 report be compared to those used in the 2000 report and that any differences be evaluated for significance.	Response in progress. OSAP prefers that assumptions are consistent with NETL's Systems Analysis Guidelines. Please contact John Wimer to obtain most recent guidance and to assess whether the use of NETL's Power Systems Financial Model should be used.
4.62 NETL	*Cost Estimating Methodology*, page 22: A definition of economic terms (book life, TCR, etc.) should be included in an appendix.	Presumably this meant comment 47 above in which case the response is the same.
4.63 ?	*Cost Estimating Methodology*, page 22: Specify whether the economic analysis has been conducted on a utility-owned basis or on an IPP-owned basis. Define sensitivities associated with the assumption.	Response in progress. Again, contact Wimer for guidance.
4.64 -	*Cost Estimating Methodology*, page 22: Were the O&M costs based on the use of a Long Term Maintenance Agreement (LTMA) for the NGCC cases? If not, why not and what are the sensitivities?	Presumably this meant comment 47 above in which case the response is the same.
4.65 -	*Cost Estimating Methodology*, page 22: In paragraph 3, distinguish the inventories among the technologies.	Response in progress.
4.66 NETL	*Cost Estimating Methodology*, page 23: The "bottoms-up" estimating approach needs further discussion for clarity.	Don't agree but could be convinced otherwise. This should be addressed if comment 9 in guidance document is followed.

No.	COMMENT	RESPONSE
4.67 -	*Cost Estimating Methodology*, page 23: Clarify whether the project uncertainty varied among technologies, and provide the rationale.	Contingencies are a line item in the cost sheets and can be determined there. Agree with reviewer....clarification and rationale needed as per comment 7 in guidance document
4.68 ?	*Cost Estimating Methodology*, page 23: Provide the rationale for developing O&M costs on a quantitative basis for demonstrated technologies.	Response in progress. O&M costs do need some explanation. A potential anomaly surfaces when IGCC O&M costs are compared. The O&M varies between cases in proportion to the differences in capital cost of each configuration. However, if all gasifier configurations contain essentially the same unit operations, why would O&M vary so much between cases? I'm guessing that O&M is scaled from capital cost, and this may not be an appropriate estimate of how much labor, etc is needed.

No.	COMMENT	RESPONSE
4.69 -	*Cost Estimating Methodology*, page 23: Define the number of operators assumed for each technology. Specify the number of maintenance personnel required for each technology.	Information is in cost detail sheets.
4.70 -	*Cost Estimating Methodology*, page 23: Defining maintenance costs as a factor of capital costs is not appropriate for combustion turbines.	Doing anything else was a greater level of detail than warranted in this study.
4.71 -	*Cost Estimating Methodology*, page 23: The approach to byproduct credits/costs should be reconsidered. The current approach unfairly penalizes the NGCC cases.	Byproduct credits/costs have a minor impact on COE.
4.72 -	*IGCC Power Plants*, page 27: At the end of the third paragraph, add a reference to Section 3.1.3 for clarity.	Typo in comment?

No.	COMMENT	RESPONSE
4.73 -	*Residual Nitrogen Injection*, page 28: In the second paragraph, the heat rate implications associated with nitrogen injection should be discussed.	The general approach used for the amount of nitrogen dilution vs. syngas humidification was to maximize the syngas humidification and then dilute to the target for NOx emissions with nitrogen. The idea being to minimize the nitrogen compression. It is unclear if GE actually derated the gas turbine for the data provided as a result of increased water content in the machine. If so, and the heat rate of the gas turbine were reduced as a result, the magnitude of the reduction could be requested from GE. We asked GE about the difference in GT heat rate for syngas vs. hydrogen firing after they provided the data and were unable to extract an explanation at the time. They did not mention this effect when providing the data either. Addressed in comment 4 in guidance document.

No.	COMMENT	RESPONSE
4.74 +	*Residual Nitrogen Injection*, page 28: As written, the two bullets appear to contradict each other. The first bullet states that firing temperatures are maintained at optimum levels, while the second states that firing temperatures are reduced. Clarification is needed.	Both are true. The firing temperature is reduced compared to natural gas firing, but it is optimized for our system. Will re-write to make more clear.
4.75 -	*Combustion Turbine*, page 43: Has the assumption that the advanced F Class turbine will be commercially available to support a 2010 start date in high hydrogen syngas been confirmed with GE, and will they offer any performance guarantees?	A study assumption was that all technologies will be available for 2010 start-up. Explain that assumption is that it will be available in that timeframe, but due to uncertainties in performance in that timeframe, appropriate contingencies were added. The added contingency should be explicitly stated and justified.
4.76 -	*Combustion Turbine Package Scope of Supply*, page 44 Exhibit 3-10, Item 5.2 Fuel Oil System: Is the backup fuel natural gas or fuel oil? If oil is to be used, is the atomizing air module included in the cost? Should a natural gas fuel system be included?	This is a defined standard package. These details are beyond the scope of the study. It is not clear how backup fuel is handled.
4.77 -	*Combustion Turbine Package Scope of Supply*, page 44 Exhibit 3-10, Item 6.0 Starting System: Does the estimate include a starting motor or static start? The costs are not the same.	See comment 4.74.
4.78 +	*Combustion Turbine Package Scope of Supply*, page 44 Exhibit 3-10, Item 7.1 Generator: Change H2 to H_2 (typo).	Will make change.
4.79 +	*Combustion Turbine Package Scope of Supply*, page 44 Exhibit 3-10, Item 8.0 Miscellaneous: Commas need to be added to separate individual pieces of equipment (typo).	Will make change.

No.	COMMENT	RESPONSE
4.80 -	*Combustion Turbine Package Scope of Supply*, page 44 Exhibit 3-10, Item 8.0 Miscellaneous: Are spare parts included?	See comment 4.74.
4.81 -	*GEE IGCC Cases-Key Assumptions*, page 56, Exhibit 3-15: Define the assumed point of blowdown discharge (property boundary?). This comment applies to all cases.	This is defined in BOP basis tables.
4.82 -	*Case 11- PC Supercritical without CO_2 Capture*, Exhibit 4-31, page 362: Since the 2000 and 2006 reports both evaluate supercritical PC without carbon capture, a comparison of predicted plant performance was made to verify consistency. The plant output in the 2006 report is 593 MWe, while the plant output in the 2000 report is 491 MWe. As shown in the following table, there are a number of differences that do not appear to be related directly to the difference in output.	If any inconsistencies exist, the errors are believed to be in the earlier report. The validity of rankine cycle efficiencies has been called into question. The efficiency used for the SC PC in this study appears to be 1-2% points too low as compared to efficiencies published in comparable studies with similar steam conditions. Furthermore, the SC PC w/o CO_2 capture has steam conditions of 3500psig/1100F/1100F and a net plant efficiency of 38.5%. The older study had lower steam conditions for the PC case w/o CO_2 capture yet the net plant efficiency was 2% higher at 40.5%. The design conditions and fuel was the same in both studies. Investigate why these

Predicted Plant Performance Comparison

Parameter	2006 Report	2000 Report
Total Steam Turbine Power (kWe)	593,470	498,319
Auxiliary Load Summary (kWe)		
Coal Handling and Conveying	300	390*
Limestone Handling and Reagent Preparation	1090	920
Pulverizers	2350	1860
Ash Handling	2120	1670
Primary Fans	1250	1220
Forced Draft Fans	2620	970
Induced Draft fans	9280	5050*
SCR	380	100*
Baghouse	100	
ESP		1000
FGD Pumps	6620	3450*
BOP	2000	2000*
ST Auxiliaries	1000	400*
Condensate Pumps	820	590*
CW Pumps	9440	3540*

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td></td><td>
<table>
<tr><td>Cooling Tower Fans</td><td>2410</td><td>2030</td></tr>
<tr><td>Transformer loss</td><td>1730</td><td>1140*</td></tr>
<tr><td>Total Auxiliaries, kWe</td><td>43,240</td><td>29,050*</td></tr>
<tr><td>Net Power, kWe</td><td>550,230</td><td>462,058</td></tr>
<tr><td>Net Plant Efficiency, %, HHV</td><td>38.5</td><td>40.5*</td></tr>
<tr><td>Net Plant Heat Rate, Btu/kWh</td><td>8857</td><td>8421*</td></tr>
<tr><td>Coal feed, lb/hr</td><td>417,731</td><td>333,542</td></tr>
</table>

An attempt was made to compare the above auxiliary load data using the ratio of plant outputs. Areas of apparent inconsistency have been highlighted. Since these data affect net output, heat rate, and efficiency, it is recommended that the above, highlighted values be reviewed to determine the basis for the differences.</td><td>differences.</td></tr>
<tr><td>4.83 +</td><td>References, page 498, Reference 28: The GE report referenced should be GER-3567H not GER-3657H.</td><td>Will make change.</td></tr>
<tr><td>4.84 -</td><td>Listing of Other Technology Comparisons:

• “COAL-Technology-2015.” Western Governors Association. October 20, 2005. http://www.westegov.org/wga/initiatives/cdeac/Coal-technology-2015.xls. June 19, 2006.
• “A Comparison of Combustion Technologies for Electric Generation.” Pembina Institute. July 1, 2001.
• Simbeck, Dale. “CO_2 Mitigation Economics for existing Coal-Fired Power Plants”. SFA Pacific, Inc. May 17, 2001.
• Hawkins, David. “Speeding CCS Deployment.” Natural Resources Defense Council. November 2005.
• Johnson, Timothy; Keith David. “Electricity from Fossil Fuels without CO_2 Emissions: Assessing the Cost of Carbon Dioxide Capture and Sequestration in US Electricity Markets.” Carnegie Mellon University.
• Henderson, Colin. “Towards zero emission coal-fired power plants.” International Energy Agency. September 2005.
• “Clean Coal Symposium.” EPCOR Generation Inc. April 28, 2005.</td><td>Duly noted.</td></tr>
</table>

No.	COMMENT	RESPONSE
	• Narula, Ram; Wen, Harvey; Himes, Kenneth. "Incremental Cost of CO_2 Reduction in Power Plants." Bechtel. June 3, 2002. • "Bulk Electricity Generating Technologies." May 2005 • Breton, David L.; Keeler, Clifton G. "Comparative IGCC Performance and Costs for Domestic Coals." ConocoPhillips. October 11, 2005. • Berg, David; Paterson, Andrew. "Understanding Gasification Incentives: Risks, Benefits, & Cost." DOE Office of Policy & International Affairs. October 10, 2005. • "IGCC Comparative Economics." Levitan & Associates, Inc. March 29, 2006. • Booras, George; Holt, Neville. "Pulverized Coal and IGCC Plant Cost and Performance Estimates." Gasification Technologies. October 6, 2004. • Imai, Nobuo; Ishida, Kazuo. "Economic Study on CO_2 Capture and Sequestration from PCF Flue Gas." Mitsubishi Heavy Industries. • Bernstein, Sanford. "AEP Environmental Roadshow." American Electric Power. April 14, 2005. • Rubin, Edward S.; Rao, Anand B.; Chen, Chao. "Comparative Assessment of Fossil Fuel Power Plants with CO_2 Capture and Storage." Carnegie Mellon University. • Wilkie, Martin; Uglow, Ben. "Capital Goods – Clean Coal: Opportunities Alstom, GE and Siemens." Morgan Stanley. January 24, 2006.	

No.	COMMENT	RESPONSE
5. Comments – Set 5 [DMT]		
5.1	**General:** This assessment of the DOE/NETL 2006 Cost and Performance Comparison of Fossil Energy Power Plants, Volume 1, is based on a complete review of the 498-page document including all 12 cases. It concludes that the technical and economic assumptions, methodology, and results presented in the draft are an excellent effort to make a comparison of the advanced technologies. The suggestions and comments below are aimed at the small further effort needed to make this draft reasonable and credible.	No response required.
5.2	**Technical / Economic Assumptions:** Assumptions used for the draft report are well explained and conform to industry standards. In addition, potentially controversial assumptions such as fuel costs and capacity factor are covered by sensitivity analysis to allow readers to maneuver on their own. The basic outputs and heat rates fit within the reviewer's experience. It does appear that the calculations may not include commercial guarantee margins. For example, Case 1 shows a net output of 643.5 MWs whereas GEE advertises 630 MWs. There are a few technical assumptions that need further study to make sure that all the conclusions drawn are valid.	No response required.
5.3 +	**Methodology:** The methodology for the report is excellent, allowing the reader to understand the detail behind the results. The thoroughness is very important in such a complex analysis of competitive technologies. Since the technologies are mostly new, and in many instances still developing, it is important to identify the differences rather than the exact results. The methodology used by DOE in the following items is extremely important in developing credibility.	

No.	COMMENT	RESPONSE
	• Simulating the various processes • Developing performance by producing heat and mass balances • Sizing major pieces of equipment for cost projections • Bottoms-up estimate • Carrying through to the correct comparison parameter – Cost of Electricity. In addition, there are many assumptions needed and a deep understanding of the inner workings of each technology requiring careful explanations. The draft has made a good attempt to make such explanations. However, since very small technical or judgment errors can reverse the comparative results, it is essential to compel a complete technology vendor review to eliminate as many of these controversial items as possible. It is understood that the vendors are extremely busy and not necessarily cooperative, but credibility depends to some extent on vendor sign-off. It will be hard to get their attention without providing some of the conclusions so they can see where they stand on various parameters. That is not normally done in a bid situation but in this instance the document will become public, so providing comparative results should be an acceptable practice. *Some examples of areas for further study are given below in the Specific Comments.*	Results were sent to GE, CoP and Shell. Only GE responded.
	The particular method of oversizing the CO_2 capture cases for an equal net output basis is good, as that is how the market will want to view the results.	
	However, the treatment of emissions, while in most cases accurate, does not discuss or give credit where credit is due. There probably should be a specific discussion of the missing value of credits. There is no industry agreement on the worth of emissions performance but without a value the comparison charts do not get the point across. Also, the particular methodology used for emissions calculations does not seem to relate from case to case. It will be very confusing for readers to have different NO_x, SO_x, and CO_2 figures in similar cases without a better explanation. For instance, CO_2 capture for IGCC varies from 94.5 percent to 88.7 percent, and SO_x varies by a factor of 3 in IGCC cases and by a factor of 8 with PC cases. *See Specific Comments below.*	Will add additional discussion.

No.	COMMENT	RESPONSE
5.4	**Results:** In general, the results fit within the experience of this writer in that IGCC (first of a kind) plants are normally more expensive than PC plants with their extensive commercial background. I am surprised to see that the recent development of larger, more efficient gas turbines combined with larger, matching gasifiers did not seem to have much effect. The change of the same two-train IGCC plants from 500 MW in past studies to 630 MW each seemingly would have reduced the gap with PCs. There is another anomaly in that Shell IGCCs without capture have not normally shown lower COE in comparison with GEE IGCCs without capture in past studies. *See Specific Comments for possible technical issue below.*	Shell COE is greater than GE in this study as well.
5.5 -	**Specific Comments:** *The following specific comments are organized by page number where the item first appears, but they frequently apply to the same subject on later pages and across the cases.* Page 5: Second-to-last bullet – It is not valid to compare NGCC and PC each at 85 percent capacity factor, as that is not how the industry dispatches such plants (see *#5.7*, below).	Accounting for dispatch order is beyond the scope of this study. Results are also shown at 65% CF if that is a more desirable comparison point for the reader. See comment 6 in guidance document.
5.6 ?	Page 8: The definition of capture – "carbon input with the coal less the carbon exiting with the slag" – is new to me and becomes problematical later due to a lack of discussion of the carbon conversion percentage differences in the slag for each case. The modeling assumption tables show the carbon conversion for each IGCC case and the carbon balance tables show a 3-to-1 difference. Is this definition driven by the methodology of always using 95 percent capture in the syngas and, if so, is this a valid industry definition? It seems to me that we are after 90 percent capture of the carbon in the coal, period. Do the	The general approach used was to maximize water gas shift (98% conversion of CO to CO_2) and Selexol CO_2 capture (95%). Generally, this was in response to the apparent inability of E-Gas IGCC

No.	COMMENT	RESPONSE
	technology vendors always use 95 percent?	systems to achieve 90% CO_2 capture due to elevated methane content of the syngas. The result is greater than 90% capture in the GE and Shell cases.
5.7 -	Page 10: Comparison of COE for an NGCC at 85 percent CF with an IGCC or PC at 85 percent CF can be very misleading. Economic dispatch for a plant with 7.46 $/MMBtu NG cost vs. 1.34 $/MMBtu for coal is likely to be below 50 percent CF. It might be helpful to show the NGCC numbers in italics or a different color and include a discussion to avoid the confusion.	See comment 5.5. Addressed in guidance document item #6
5.8 -	Page 10: The chart is very helpful in collecting the CO_2 capture data and showing the avoided cost. The reader trying to make a technology choice needs, however, some discussion of the value of improved CO_2 emissions performance. It may be that only a caveat is necessary.	Since there are no current regulations it would be difficult to provide a meaningful discussion.
5.9 -/+	Page 11: This chart is a good data source but lacks the ability to convey to the reader the value of improved emissions and the effect on current or future economics. It is hard to see that the cases are equivalent in the comparison. Some questions are as follows: • SCR has not been applied to IGCC but has been included in PC. Even so, there is twice as much NO_x in the PC cases with capture. Maybe the chart should say, "without SCR" for the IGCC cases. • Where is the information that IGCC can be lower by a factor of 5-10 either with SCR or with advanced combustors under DOE funded development? • Would lbs/MWhr of CO_2 be better here, since the plant sizes are different?	Lists technologies used – not ones not used. No SCR is defined in other places. Will add a comment. Presented as such in ES-7.
5.10 +	Page 19: The CO_2 paragraph is a little difficult to understand.	Will assess and modify if necessary.
5.11 -	Page 22: Prior studies were 3 - 4 years old and need verification by vendors today. Is the labor union or non-union? (There is a 200$/Kw difference.)	Actual labor rates are provided in cost sheets.

No.	COMMENT	RESPONSE
5.12 ?	Page 23/24: I agree with the contingency discussion but would prefer to see some differentiation between standard CC and non-standard process areas. Maybe this is taken care of by the nth plant methodology.	Not sure what differentiation is desired. Will be addressed by item 7 in guidance document
5.13 +	Page 27: According to the second paragraph, the ability to compare capture cases at the same net output is not possible due to the limiting factor of the fixed GT size. That sounds reasonable. I couldn't find the reference 2.6 explanation, so I am not sure whether it is adequate. Below, you will find information suggesting that the capture Case 2 was oversized by only 3.5 percent. The PC plants follow the desired oversizing methodology but are matched to the IGCC 550 MWs capture case size, so a conflict is avoided.	Should have been Section 1 (not 2.6).
5.14 +	Page 27: Paragraph 3 – "more reliable operation" should read "parts life equivalent to NGCC applications."	Will make change
5.15 +	Page 29: • EP ASU paragraph: Polk also uses all of its N_2 in the GT and now has retrofitted partial air extraction to obtain more oxygen and nitrogen. • ASU Basis paragraph: 5 percent extraction is not necessarily a common parameter between cases and can affect the comparative results; see below.	Will so note
5.16 ?	Page 31, 3.1.3: The industry uses terms of sour gas shift and sweet gas shift.	Do we want to change this in the many places it appears? Yes

No.	COMMENT	RESPONSE
5.17 +	Page 32, 3.1.5: Wrong! - 30 ppm S in "Undiluted" syngas results in 4 ppmvd SO_2 in the stack; the ratio is approximately 7 to 1. This point is causing many errors in the industry, as the calculation is not easily understood. Also, different technology suppliers use different methods of introducing the diluents. There are three methods: • Diluent mixing directly into the "undiluted syngas" at full syngas pressure. • Diluent injection directly into the GT combustor with an advantage of lower compression power. Is this what was done for the non-capture IGCC cases? • Partial diluent mixing/partial diluent injection; used primarily for capture cases with hydrogen fuel. Subsequent paragraphs use < 5 ppm SO_x instead of 2. As an aside, 2 ppm SO_2 in the stack and 15 ppm S in the syngas is what should be used for SCR IGCC cases.	Will verify number and fix accordingly.
5.18 -/+	Page 43, 3-9: Natural Gas might be needed in the table title due to the change of subject, as the previous information is discussing syngas; or perhaps the table should show both NG and syngas ratings. An important missing feature of these turbines is the ability to co-fire NG and SG, allowing 95 percent power availability in case of process difficulties. This should be mentioned somewhere in the text.	Text introducing the table says natural gas. Will add such a statement.
5.19 +	Page 45: Replace "Unlike natural gas … position is reached." with "Inlet Guide Vanes (IGVs) and firing temperature are used to maintain the turbine output at the maximum torque rating, producing a flat rating up to the IGVs' full open position."	Will make change
5.20 +	Page 46, First paragraph: Suggest removing "both" and"gasifier".	Will make change
5.21 +	Page 47: Replace "dry low NO_x … use staged combustion" with "Diffusion combustors and syngas dilution."	Will make change
5.22 ?	Page 53: The industry uses the term Synthesis Gas Cooler (SGC) and it can be preceded by radiant (RSGC) rather than RSG, although this is not terribly important.	Same issue as 5.16. Use industry terminology.

No.	COMMENT	RESPONSE
5.23 -	Page 55: 63 percent solids sounds low. Was that specified by a technology vendor?	Per presentation made by ConocoPhillips at the 2005 GTC for the slurry-ability of different coals, 63% is pretty close to what you would get from Illinois 6. This is exactly the kind of info that should be referenced to add credibility.
5.24 +	Page 57, 3-16: This chart uses a more correct number for SO_x at < 5 rather than the previously mentioned 2 ppm.	Will verify number per comment 5.17.
5.25 NETL	Page 63 et al.: The following chart shows that N_2 used in the GT for Case 1 is approximately 55 percent of that produced in the ASU. That suggests that the modeler used water to its maximum (humidification) and N_2 to its minimum for the GT. Most previous work has found that a more optimal system uses maximum N_2 plus minimum water. Some inter-related reasons include: • The 45 percent N_2 not used was partially compressed in the elevated pressure ASU (to about 60 psi) and that energy is lost. In fact, most studies suggest not using an EP ASU if only 55 percent N_2 was to be used. • The higher moisture content forces the GT firing temperature to be reduced, further degrading efficiency. • The heat of vaporization of the excess water is lost up the stack. • More nitrogen than water is needed to get the same NO_x reduction, meaning more GT output for a full N_2 injection case. • The Shell Case 5 uses 89 percent of its potential N_2, possibly changing the whole relationship against GEE and reversing the economic results. • The table below has been made to study the effects of this methodology. The wide variations in N_2 use may suggest that this is not an optimal comparison.	Similar to comments from Norm Shilling of GEE. Philosophically, do we want to re-run cases to try to optimize the systems. See comment 4 in guidance document.

No.	COMMENT	RESPONSE
	Effects of methodology	

Item	GEE Case 1	E-Gas Case 3	Shell Case 5
N_2 to GT (1000 lbs/hr)	785	1016	1087
N_2 (% of available)	55	65	89
Air Ext from GT (1000 lbs/hr)	286	295	428
Air to ASU total (1000 lbs/hr)	1833	1562	1543
ASU MAC Comp (HP)	59.8	49.8	43.8
N_2 Comp (HP)	23.5	31.6	35.9
Oxygen Comp (HP)	11.5	8.8	8.9
Total Comp (HP)	94.8	90.2	88.6

No.	COMMENT	RESPONSE
5.26	Page 64: I like the methodology of including the specific syngas composition in the table. It is very important for the GT manufacturers to be able to judge whether the system is producing the optimal composition.	No response required. I was able to find CoP gas compositions on their web page with my first Google search. Similar info for other gasifiers may be available as well. Gas compositions should be compared to these sources and referenced to add credibility. Schoff indicated that the gas compositions he estimated were proprietary, but some of this data appears to be available publicly. RDS should do a search to find out.
5.27 ?	Page 66, Emissions Table: The emissions tables are a big help as a source of data but they have several issues for further study: • CoalFleet numbers for 30 ppm S in syngas and 4 ppm SO_x in stack are 0.0128 lb/MMBtu vs. 0.010 for DOE Case 1. This is approximately a 28 percent discrepancy. The CoalFleet numbers came from GEE. Variations of this size could be correct, but the author should make sure the calculations are verified by the technology vendor. • CoalFleet NO_x @ 15 ppmvd is 0.064 lb/MMBtu vs. DOE Case 1 @ 0.052, representing a discrepancy of about 23 percent. The CoalFleet numbers came from GEE. Variations of this size could be correct, but the author should make sure the calculations are verified by the technology vendor. • Particulates seem to be very low; they are probably for only the filterable front half of the sampling train. CoalFleet uses 18 lb/hr = 0.0071 lb/MMBtu vs. 0.006 for DOE.	Response in progress. RDS should investigate and verify.

No.	COMMENT	RESPONSE
	However, total particulates including condensibles for CoalFleet @ 30 ppm S in syngas are 37 lb/hr = 0.0145 lb/MMBtu vs. DOE?? (0.006) DOE's 127 tons/(0.85x8760) = 34 lbs/hr which doesn't match either the 18 or 37 lb/hr. Again, confirmation is needed from the technology vendor. • Lbs/MWhr are probably based on net generation, which should be noted in the table as EPA is pushing gross generation, which has a confusing meaning for IGCC vs. PC due to the large IGCC auxiliary losses. • DOE Case 3 has SO_x at 0.003 lb/MMBtu vs. Case 1 at 0.010 for same 30 ppm S in syngas. This is a factor of 3?? I would suggest that a comparison table be made of all cases to see what it tells us.	
5.28	Page 67: I like the methodology of the black box Carbon and Sulfur balances to support the credibility.	No response required.
5.29 +	Page 68: What fire tube boiler?	Will change to water tube syngas cooler.
5.30	Page 75: I like the energy and mass balance tables for credibility.	No response required.
5.31 +	Page 76: "Water/syngas" should be "Water vapor/syngas."	Will make change.
5.32 NETL	Page 78: The 5 percent air extraction assumption may not be optimal and surely would not be the same for all cases. With reference to the table above, it can be seen that using more N_2 and less humidification should allow a higher level of air extraction, potentially reducing the large MAC compressor power requirement especially for Case 1. GEE uses about 6 percent air extraction in their reference design but this low figure may be needed for a reference plant handling various coals, etc. It is the combination of 55 percent N_2 injection and 5 percent extraction that seems strange; technology vendor confirmation is needed.	See comment 5.25. Verify if possible the level of air extraction GEE recommends.
5.33 -	Page 79: The methodology of sizing the components on the extensive major equipment list is very important. One other thought to enhance credibility is to name the components that had vendor estimates and date vs. the items in the factored estimate.	Not practical. Do not agree. Something more needs to be included to justify the sizing and cost estimates.
5.34 -	Page 89: Some people might say the ASU costs are low but if you have recent quotes, so be it.	Praxair confirmed cost numbers used.

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td>5.35
NETL</td><td>Page 93: The effect of hydrogen fuel with humidification and low N_2 injection rate precludes the use of air extraction for reducing the MAC size. The following rough table was made to consider the 3-to-1 effect of H_2 fuel on turbine flows, i.e., power. The table suggests that it is possible that full N_2 dilution with reduction in humidification or moisturizing of the nitrogen may improve the CO_2 capture cases by raising the flow through the turbine toward the same exhaust flow.

3-To-1 Effect Of H_2 Fuel On Turbine Flows
<table>
<tr><th>Item</th><th>Case 1</th><th>Case 2</th></tr>
<tr><td>Syngas CO Vol. %</td><td>33</td><td>0</td></tr>
<tr><td>Syngas H_2 Vol. %</td><td>32</td><td>75</td></tr>
<tr><td>Syngas H_2O Vol. %</td><td>16</td><td>20</td></tr>
<tr><td>Syngas CO_2 Vol. %</td><td>14</td><td>2</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>GT Flow SG (1000 lbs/hr)</td><td>1085</td><td>328</td></tr>
<tr><td>GT Flow N_2 (1000 lbs/hr)</td><td>785 @ 55% of available</td><td>965 @ 65% of available</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Exhaust Flow (1000 lbs/hr)</td><td>8,679</td><td>8,439</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Coal and Gross Power (% approx.)</td><td>100</td><td>103.5</td></tr>
</table></td><td>See comment 5.25.</td></tr>
<tr><td>5.36
+</td><td>Page 97: A better explanation is needed as to why Case 2 has 94.5 percent capture and Case 4 has 88.7 percent capture, other than the obvious methane differences. It would seem that a method is needed of valuing the extra capability. I like the information on the differences but maybe some mention should be made about the cost to do more than 90 percent capture of the carbon in the coal. In fact, the industry needs some information on the optimal capture rate. One recent IGCC paper showed 80 percent extra COE for capture up to 95 percent. They are now reconsidering such a high rate.</td><td>CH_4 is the primary difference. Make sure this is explained sufficiently.</td></tr>
<tr><td>5.37
-</td><td>Page 127: What Quench?</td><td>See comment 10.31.</td></tr>
</table>

No.	COMMENT	RESPONSE
5.38 +	Page 139: Carbon in slag is 1/3 of Case 1. If that is just the carbon conversion factor, an explanation might help.	An explanation will be added.
5.39 ?	Page 145: How does the temperature get from 700 ºF to 310 ºF? Is it really a "Quench" Scrubber?	Response in progress.
5.40 ?	Page 195: The Demkolec plant is now owned by NUON, which has announced a 1200-MW IGCC expansion. TECO Polk has also announced a 630-MW expansion.	Is this relevant to the study? …in the sense that it illustrates continued interest and trust in IGCC technology
5.41 +	Page 283: I like the methodology of oversizing the capture cases to equal net output and the explanation of the methodology. Maybe it should also be pointed out that the 550-MW size was chosen to match the IGCC capture cases for the comparison.	Will so note if in fact this was true. Is this true???
5.42 +	Page 290: What is the SO_2 polishing step and what is the reality of 98 percent sulfur removal on a daily basis? I am finding utilities resisting more than 95 percent for permits for continuous operation.	Will clarify that SO_2 polishing step is part of the Selexol process. UOP did not provide details.
5.43 +	Page 307: PC emissions are higher than IGCC. SO_x is 8 x while Hg is double. Some discussion of this comparison is needed.	Additional discussion will be added.
5.44 -	Page 332: If the SO_x into the CDR is 10 ppm, how much is removed in the CDR and is that what NIL means?	Text states that this is the case.
5.45 -	Page 432: Why is DLN not used instead of MNQC combustors to save water and reduce the SCR size, cost, and maintenance; alternatively, could a study be referenced showing the economics for this choice of MNQC?	DLN is not available in the advanced F class turbine.
5.46 ?	Pages 443/444: Where is the amount of steam needed for the MNQC combustors and was it subtracted from the ST MWs? Without DLN combustors, steam is needed to reduce NO_x from 250+ ppmvd to 25 ppmvd prior to the SCR.	Response in progress.

No.	COMMENT	RESPONSE
5.47	Pages 497/498: The literature referenced seems appropriate. Conspicuously missing are any references from ConocoPhillips, Shell, Siemens, or boiler makers other than Alstom.	No response required. I agree with reviewer….seems irresponsible to have not reviewed recent public information from the gasifier and boiler manufacturers. This should have been part of the "due diligence" and initial research done for the analysis. Please determine if any information is available on these reactors that can be included.

No.	COMMENT	RESPONSE
6. Comments – Set 6 [JPCTJT]		
6.1 +	**Summary:** There are substantial differences between an IGCC power plant that is equipped for CO_2 capture and one that is not. Specifically, the inclusion of a water gas shift (WGS) process results in significant changes to the steam cycle and the reduction in mass flow to the turbine, resulting in a number of process flow and integration changes between the two plants. *However, in evaluating the "capture" and "no capture" case presented in this recent NETL report, there appear to be a number of inconsistencies in equipment costs, including identical combustion turbines having different costs.*	All items from reviewer six have been submitted to WorleyParsons estimating for response. It is appropriate to have the cost experts review all costing methodology and results, including the issues highlighted by this reviewer. Consistency is very important even if overall results change very little. It provides credibility.
6.2	**Background:** NETL recently circulated a draft study entitled *2006 Cost and Performance Comparison of Fossil Energy Power Plants*, which examines the cost and performance of various types of power plants expected to start operation in 2010. Two of the cases presented by this report deal with IGCC plants utilizing GEE gasifiers: Case 1 of the study is a normally configured plant while Case 2 is configured for CO_2 capture. Each plant uses a dual train GEE gasifier, Advanced F Class gas turbine, and custom sized steam turbine. It is pertinent to note that the plant with CO_2 capture has a slightly larger coal flow rate, presumably to make up for fuel gas heating value lost in shifting CO, providing the same heating value fuel gas to the combustion turbine as in the plant without capture. It is possible that some H_2 is lost in the CO_2 capture stage as well, but it is unclear if this has been considered or not. As a result of the increased coal flow rate, an increased O_2 flow rate to the	

No.	COMMENT	RESPONSE
	gasifer is required. The steam turbine in the capture case is smaller, which is assumed to be a result of steam bled off for the WGS and/or for Selexol™ regeneration.	
6.3	**Data:** A table (Attachment 1) was generated that compares the percentage change in unit costs between these cases, utilizing the detailed cost estimates for each case, as found in sections 3.6.1 and 3.6.2 of the cost and performance study. The table given in Attachment 1 lists the cost areas for the IGCC power plant, along with the associated cost breakdown into the "Bare Erected Cost" – consisting of equipment, material, and labor costs – project contingency costs, and the resulting cost in both thousands of dollars ($x1000) and dollars per kilowatt of net power generation ($/kW). The "Engineering CM, H.O. & Fee" column found in the source tables was found to equal 10 percent of the "Bare Erected Cost" and has been omitted for brevity. The values presented are the percentage change in cost between the plant without CO_2 capture (Case 1) and the plant with CO_2 capture (Case 2). **A positive value indicates that the item listed is more expensive for the plant with CO_2 capture. Similarly, negative values (highlighted in red) are instances where the item is less expensive in the plant with CO_2 capture.** The values in the dollar per kilowatt column have been adjusted to account for the difference in net power generation between the two cases. This was done by assessing the percentage difference in the reciprocal of net output ($1/kW_{net}$) between the two cases, and subtracting this value from the percentage increase in plant cost. This is expected to allow an "Apples to Apples" comparison for this metric.	
6.4	**Concerns:** The gasifier in the CO_2 capture case is designed to process 3,300 tons/day as compared to the specification of 3,200 tons/day for the plant without capture. It is expected that the larger throughput would increase the cost of the unit; however, no cost increase is reflected (line item 4.1). Furthermore, the cost of the gasification foundations (line item 4.9) decreases by 0.5 percent, which seems counter-intuitive.	

No.	COMMENT	RESPONSE
6.5	The air separation unit (ASU) in the CO_2 capture case is designed to generate 2,800 tons/day of O_2 as compared to the specification of 2,700 tons/day for the plant without capture. Furthermore, the air, O_2, and N_2 compression systems are sized to process increased volumes of gas. These increases in throughput are not reflected by an increase in cost of the "ASU/Oxidant Compression" item above (line item 4.3a).	
6.6	The combustion turbines specified in the two cases are identical: two 232-MWe gas turbine generators, which meet the Advanced F Class requirements. What is the source of the 5 percent increase in cost for the turbines in the plant with CO_2 capture (line item 6.1)?	
6.7	The plant with CO_2 capture processes more coal using the same GEE gasifier as the plant without capture, but there is a 4.5 percent reduction in the slag dewatering and cooling cost for the plant with capture (line item 10.1). This seems inconsistent with the increased flow rate.	
6.8	There is a 4.1 percent reduction in Instrumentation and Control costs (line items 12.4-12.9) for the plant with CO_2 capture. Is this the result of the decreased net power output? Is the plant with CO_2 capture less complex and/or does it require fewer controls than the plant without?	
6.9	The majority of site improvements, and buildings and structural items, decreased in cost (line items 13.1-13.3 and 14.2-14.9, respectively) for the plant with CO_2 capture. While this is expected in the case of the steam turbine building (line item 14.2) because of the reduced steam turbine size, it was expected that more equipment and a larger site would be required for the CO_2 capture case. What is the source of these cost reductions for the CO_2 capture case?	
7. Comments – Set 7 [GB]		

No.	COMMENT	RESPONSE
7.1 ?	**General Comments:** Costs of electricity are referred to throughout the report as 10th year levelized costs of electricity. I am not sure what this means. EPRI's Revenue Requirement Methodology can be used to calculate year-by-year revenue requirements, and therefore a year-by-year cost of electricity (COE). Generally the COE (expressed in constant dollars) is higher in the initial years and declines over time. The single COE for all years that gives the same NPV as the year-by-year COEs is referred to as the levelized COE. It turns out that this single value (or levelized COE) is typically about the same value as the COE in the 10th year (assuming a 30 year project life). I believe your COEs should be referred to as either 10th year or levelized, but not 10th year levelized. Generally the COEs shown in the report are higher than EPRI would calculate for the same set of financial parameters. I would be happy to discuss this further with whoever prepared the analysis for the report.	Response in progress. This is very confusing to the reader. Please clarify what basis the COE is reported. Preferably it should be done on what is industry's standard practice. See John Wimer regarding the readiness of the Power Systems Financial Model to calculate and report this consistently.
7.2 +	For the PC cases with CO_2 capture, the report states that a polishing step is required to go from 98 percent SO_2 capture in the base case to only 10 ppm SO_2 in the CO_2 capture cases. I cannot find any description of the polishing system, nor do I find any capital costs for such a system. Have additional O&M costs been included for the polishing system?	See comment 5.42.
7.3 -	The Econamine FG Plus system described in the report does not appear to incorporate the latest improvements as described by Fluor in several recent papers and other studies, including studies by the IEA Greenhouse Gas Program (PH4/33 November 2004). These improvements include a split-flow system utilizing both lean and semi-lean amine. This split flow system, and other process improvements, have dramatically reduced the energy requirements for regeneration. A recent EPRI study of the Econamine FG process indicated that the steam requirement could be reduced from about 1750 Btu/lb CO_2 to around 1185 Btu/lb CO_2. The value I calculated from the current DOE report is about 1520 Btu/lb CO_2 or only a slight improvement over the older version of the Econamine FG process. The steam consumption for the reboiler is known to be a major cause of the net power reduction for PC plants with CO_2 capture.	The quote is more recent than the IEA report. Fluor indicated that this design is more optimized as a system than the IEA report version and that the cost of the system is reduced. Others also noted poor econamine performance. Please verify and explain differences when compared to these cited sources.

No.	COMMENT	RESPONSE
7.4 -	**Specific Comments:** Exhibit ES-7: It would also be helpful to include the amount of CO_2 captured (lb/hr or ton/yr) and the overall % CO_2 capture for each case.	Other reviewers commented that this Exhibit is already too busy.
7.5 -	Exhibit 2-5: Why is the IGCC designed to achieve 99+ percent sulfur capture, yet the NO_x emissions are relatively high at 15 ppmv? Typically an owner would only go to deep sulfur capture if the IGCC were going to include SCR for NO_x control.	BACT was applied in each case.
7.6 NETL	Pages 21 and 22, Raw Water Usage: The report seems to assume that the water consumption is the same for IGCC with and without CO_2 capture. What about the water consumed in the shift reaction for the capture case? The same comment applies to the PC plants with and without capture. The condenser duty, and therefore the water evaporation loss, will be lower for the PC plant with capture, since such a large percentage of the LP steam is extracted to provide heat for the Econamine reboiler. There may be other compensating factors, but it would seem that the water usage should be different for the cases with and without capture.	This is a valid point – will have to consider possible options. Water balances are needed, see comment 5 in guidance document.
7.7 -	Page 22, Cost Estimating Methodology: For which plant areas did the vendors supply quotes?	None specifically for this study. Costs were from quotes for other WorleyParsons projects. To the best of Parsons ability, the vendor supplied quotes should be identified. The costs need to be defended with this type of reference.

No.	COMMENT	RESPONSE
7.8 -	Exhibit 2-9: It is unlikely that these types of projects would be able to get 80 percent debt financing. Also, the cost of equity seems quite high at 16.5 percent.	Won't change cost basis now. This change would be simple if using the Power Systems Financial Model. Please discuss with John Wimer considering latest guidance on cost assumptions in NETL's Systems Analysis Guidelines.
7.9 +	Exhibit 4-3: The SO_2 removal for Case 10 should also show an SO_2 polishing system. Also, the heat and material balance diagrams (see Exhibits 4-20 and 4-42) for the CO_2 capture cases do not show the SO_2 polishing system.	See comment 5.42.
7.10 +	Exhibit 5-16: Where are streams 10-13?	Inadvertently omitted – they will be added.

No.	COMMENT	RESPONSE
8. Comments – Set 8 [NHJP]		
8.1 ?	Page 10 Exhibit ES-7: The IGCC TPC estimates look a little low e.g., the CoP estimates are lower than those published by CoP in October 2005. See later notes on the detailed estimates. For IGCC the ASU estimates look low and are generally 17,350- 19,400 $/STPD of Oxygen. We now expect something more like 24,000- 25,000 $/STPD. If the ASU is adjusted to the higher cost the TPC estimates become closer to other published estimates (GE 1602 $/kW close to a published AEP #), CoP 1456$/kW and Shell 1637$/kW. We would expect the E Gas heat rate to be a little better than for GE rather than slightly greater as shown in this table. Our HR estimate for GE is about the same as in the table, but ~8640 for E Gas. The lower oxygen demand should help E Gas vis-a-vis GE. The PC TPC estimates are about 80$/kW lower than our estimates. The differential heat rate between the Subcritical and Supercritical plants with capture (1614) looks much greater than would be expected based on the differential HR without capture (532). The interim results presented in the paper given at the September 2005 Conference showed much less of a differential HR (Sub vs. Super) with capture. One variation on the comparative method used in this study would be to have the PC plants without capture designed for a higher coal feed rate so that the net power without capture would be closer to the IGCC cases without capture. It wouldn't change the essential conclusions but might blunt a potential criticism.	Response in progress. Verify ASU costs. Investigate and confirm differential heat rate between subcritical and supercritical plants with capture.

No.	COMMENT	RESPONSE
8.2 -	*Page 63, Exhibit 3-18: Why are streams 8, 9, 10, 11, &12 missing?	Considered proprietary information Please reconsider what is really proprietary….and if it is, determine if publicly available data can be used instead without significantly reducing the accuracy of the results.
8.3 -	*Page 94, Exhibit 3-33: Why are streams 8, 9, &10 missing?	See 8.2
8.4 -	*Page 135, Exhibit 3-52: Why are streams 8,9,10, 11, &12 missing?	See 8.2
8.5 -	*Page 163, Exhibit 3-63: All streams are shown. Why are they not shown in the other Stream tables?	It was an oversight, should not have been shown as per 8.2.
8.6 -	*Page 199, Exhibit 3-78: Why are streams 11, 12, 13, 14 and 15 not shown?	See 8.2
8.7 -	*Page 227, Exhibit 3-89: Why are streams 11, 12, 13, and 14 not shown?	See 8.2
	**Note: In all the above cases we recognize that the stream table doesn't have to show both streams in and out of the Mercury removal since there is no change in temperature and only minor change in pressure.*	
8.8 +	Page 68: Line 12 mistakenly mentions a firetube boiler syngas cooler. GE has a water tube radiant syngas cooler.	Will make correction

No.	COMMENT	RESPONSE
8.9 ?	Page 89, Exhibit 3-29 and all other pages containing the TPC summaries for the 6 IGCC cases: In all cases GE, CoP and Shell the cost estimates for the ASU and Gasification Syngas Cooler systems with CO_2 capture are shown as the same as those without capture. Since there is greater coal feed and oxygen usage with capture this cannot be correct. Furthermore, the main air compressor has to be increased by 25-50 percent to provide the additional air since the gas turbine compressor extraction air is no longer available. For these reasons the ASU and Gasification/SGC costs should be increased for the IGCC capture cases.	Sent to cost estimators.
8.10 ?	It is somewhat surprising to see the costs of the gasifier and syngas cooler costs so relatively similar between GE, CoP and Shell (191, 166, and 166 Million $ respectively). Generally, the CoP structure is significantly lower in height than GE or Shell because of its continuous slag removal rather than lock hoppers and because of its side by side configuration of Gasifier and SGC versus the vertical stacking of GE and Shell. In addition, the fire tube SGC has generally been assessed at about a quarter of the weight of equivalent duty water tube designs. Some of this seeming anomaly may stem from a definition of what is in each category. It is to be noted that a lot of the Shell costs are in the coal pressurization and feeding. Shell has pointed out that there is a substantial reduction in SGC costs if only 50 bar steam is generated rather than the 120 bar used in Buggenum and other earlier plant designs. I could not find what pressure steam was generated in the SGC for the Shell cases. Is it 50 barg (725 psig)?	Sent to cost estimators.
8.11 +	Page 9, Exhibit ES-6: The values for the CO_2 emissions correspond to kg/MWh not lb/MWh (see Exhibit ES-7 on the next page, the kg/MWh values are around 800 for the non-capture cases).	Will make correction.
8.12 +	Page 18, Exhibit 2-5: The NOx control technology for PCs is missing "SCR" after the word "and".	PDF conversion error – will fix.
8.13 -	Page 25, Exhibit 2-9: I'm not convinced a capacity factor (CF) of 85 percent is currently justified for IGCCs that do not have a spare gasifier. Certainly the existing fleet of coal-based IGCCs have not yet attained that CF.	This was a study assumption, curves present COE at other CF's. See comment 6 in guidance document.

No.	COMMENT	RESPONSE
8.14 ?	Page 31, Section 3.1.3: The specification for converting 98 percent of the CO to CO_2 in the shift reactors seems extreme. The later analysis for the GE and Shell capture cases shows that this is more than is needed to achieve 90 percent carbon capture.	Response in progress. Address this issue. Can the conversion be relaxed for GE and Shell?
8.15 +	Page 32, Section 3.1.5: The stack gas to undiluted syngas sulfur ratio of 2:30 ppmv doesn't look right. EPRI's calculations have shown that 30 ppmv S in the undiluted syngas will produce 4 ppm SOx in the HRSG stack.	Others have also pointed this out – will verify and correct.
8.16 +	Page 33, COS Hydrolysis: It should be noted that COS hydrolysis was first proven at the IGCC located in Buggenum, the Netherlands.	Will so note.
8.17 +	Page 37, Exhibit 3-5: It is my understanding that UOP is the supplier of the Selexol process.	Will make correction.
8.18 +	Page 4, 3.1.7 Slag Handling: The statement "solids leave the gasifier pressure boundary through a proprietary pressure letdown device to a series of dewatering bins" is not true for all technologies. I believe only E-Gas offers a continuous slag pressure letdown system. Shell and GE rely on lockhoppers to depressure the slag.	Will re-word accordingly.
8.19 +	Page 43, Exhibit 3-9: GE and Siemens are now both quoting NOx emissions of 15 ppm for their syngas-fired F class turbines.	15 ppm was used in the emissions tables, and it will be changed here.
8.20	Page 57, Exhibit 3-16: What is the basis for selecting a carbon conversion of 98 percent? Is that carbon conversion per pass or total carbon conversion? According to the EPRI final report on the Cool Water project (AP), the GE Energy gasifier at Cool Water had an overall carbon conversion of 96.9 percent on Illinois #6 coal. Perhaps, therefore the 98 percent is total carbon conversion including the fines recycle?	Please address this question.
8.21 +	Page 59, Distinguishing Characteristics: A key disadvantage of the GE gasifier design is the limited life of the refractory lining which must be replaced as often as every 12 months at a cost of circa $1 million per change-out including materials & labor*, and requires a month-long shutdown. *Clayton, S.J. et al., Gasification Technologies, Report DOE/FE-0447, U.S. Dept. Of Energy, Germantown, MD 2002*	Will so note in the text. And determine if this is included in the O&M costs.

No.	COMMENT	RESPONSE
8.22 +	Page 62, Exhibit 3-17: Unlike the other IGCC process flow diagrams, the main air compressor for the ASU is not shown upstream of stream 1.	It was shown in some cases, but not others – will be made consistent.
8.23 +	Page 63, Exhibit 3-18: The dilution N_2 stream will not be 100 percent pure nitrogen. A typical spec is >98 percent N_2. This comment applies to all of the IGCC cases. Also, there should be a note that the flow rates represent the sum of all of the trains in the plant.	If we're required to re-run the IGCC cases, this change will be made.
8.24 +	Page 76, Syngas Quench: The sentence "The water removed from the syngas quench contains all the solids that were not removed in the quench gasifier water sump" is confusing at best. I think it is trying to say some of the solids settle to the bottom of the quench water sump while the rest of the solids remain entrained in the water circulating through the quench chamber.	Will re-word to make more clear.
8.25 ?	Page 96, Exhibit 3-34: Why is the oxygen compressor load less than it was in Case 1? Case 2 consumes more O_2.	Will investigate.
8.26 ?	Page 121, Exhibit 3-44: • Line 4.3 ASU is same cost as Case 1, but more O_2 is being produced and the MAC is larger since no air is coming from GT. • Line 7. HRSG is more expensive than Case 1 even though the GT exhaust temperature is lower and therefore less steam is being raised. • Line 10. Why is Ash/Sorbent handling cost less than Case 1 when more coal is being consumed and therefore more ash being produced? • Line 12. Why would I&C cost be less than Case 1?	Sent to cost estimators.
8.27 ?	Page 131, End of paragraph #2 states gasifier 2nd stage exit temperature is 1900ºF, but Exhibit 3-50 says the inlet temperature to the syngas cooler is 1750ºF.	Response in progress.
8.28 +	Page 131, End of page: Like GE a disadvantage of the E-Gas system is the limited refractory life.	Will so note.
8.29 ?	Page 135, Exhibit 3-52: The pressure drop across the saturator is 54 psid in Case 3 versus only 24 psid in Case 1. It seems to be unnecessarily penalizing the E-Gas case.	Response in progress.
8.30 ?	Page 136, Exhibit 3-52. The temperature and pressure for stream 21 the air extraction from the CT is completely different than the values used in Case 1. Why?	Response in progress.
8.31 ?	Page 137, Exhibit 3-53: I find it highly unlikely that the E-gas IGCC would have a higher heat rate than the GE IGCC when the E-gas system has lower oxygen demand and a higher cold gas efficiency. E-Gas case needs more optimization.	Check against recent EGas reports.

No.	COMMENT	RESPONSE
8.32 ?	Page 145, Gas Scrubbing: "The cooled syngas at 154ºC (310ºF) enters the scrubber". The dry solids filter operates at 700ºF. How is the syngas cooled from 700 to 310ºF?	Response in progress.
8.33 ?	Page 159, Exhibit 3-60: Water cost is 51.5 percent less than it is in Case 1, but Exhibit 3-53 shows raw water use is 7016 gpm for Case 3 and Exhibit 3-19 shows raw water use is 8804 gpm for Case 1 (Case 2 consumption is 79.7 percent of Case 1). Either the water cost values are wrong or the water consumption estimates are wrong.	Response in progress.
8.34 ?	Page 163, Exhibit 3-63: Why is the amount of dilution N_2 (stream 4) so much less than it was in Case 3? Looking at Cases 1 and 2, the dilution N_2 is bigger for the capture case. Why isn't that so for the E-Gas cases?	Response in progress.
8.35 +	Page 194, Section 3.4.4: • There is a need to point out that Shell's oil gasification process (which started development in the 1950s) is very different from Shell's coal gasification process (down-fired, refractory-lined gasifier with one feed injector versus side-fired, membrane wall cooled gasifier with 4 feed injectors). • In the discussion about Shell and Krupp Koppers splitting, it should be mentioned that in 2000 Shell and Krupp Uhde, the owners of the PRENFLO process, agreed to join forces again in gasification and that they are jointly offering the Shell coal gasification process. • I would delete the first sentence of the last paragraph. Shell's U.S. division may have taken the lead in development from 1984 until the end of the SCGP-1 demo plant in 1991, but since 1991 the lead has definitely been Shell's international engineering and R&D group in the Netherlands.	Will make the recommended changes.
8.36 +	Page 195: The Buggenum plant is no longer owned by SEP. It was purchased by Nuon around 2000.	Will so note.

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td>8.37
+</td><td>Page 195, Gasifier capacity: The capacity of the Dutch gasifier is 2000 tpd, not 1800 tpd. The authors also want to mention the several large gasifiers under construction in China.

Shell Coal Gasification Plants in China
<table>
<tr><th>Owner</th><th>Location</th><th>Coal tons/day</th><th>Syngas 10^6 Nm^3/hr</th><th>Product</th><th>Start-up Date</th></tr>
<tr><td>Sinopec/Shell</td><td>Yueyang</td><td>2000</td><td>142,000</td><td>Ammonia</td><td>2005</td></tr>
<tr><td>Shuanghuan</td><td>Yingcheng</td><td>900</td><td>55,000</td><td>Ammonia</td><td>2006</td></tr>
<tr><td>Liuhua</td><td>Liuzhou</td><td>1300</td><td>71,500</td><td>Ammonia</td><td>2006</td></tr>
<tr><td>Sinopec</td><td>Wuhan</td><td>2000</td><td>142,000</td><td>Ammonia</td><td>2006</td></tr>
<tr><td>Sinopec</td><td>Anqing</td><td>2000</td><td>142,000</td><td>Ammonia</td><td>2006</td></tr>
<tr><td>Yunnan Tianan</td><td>Yunnan</td><td>2800</td><td>150,000</td><td>Ammonia</td><td>2006</td></tr>
<tr><td>YunnanZhanhua</td><td>Yunnan</td><td>2000</td><td>150,000</td><td>Ammonia</td><td>2007</td></tr>
<tr><td>Dahua</td><td>Dalian</td><td>1100</td><td>71,500</td><td>Methanol</td><td>2007</td></tr>
<tr><td>Yongcheng</td><td>Yongcheng</td><td>2000</td><td>130,000</td><td>Methanol</td><td>2008</td></tr>
<tr><td>Shenhua</td><td>Inner Mongolia</td><td>2x2000</td><td>2x150,000</td><td>Hydrogen for Coal Liquefaction</td><td>2008</td></tr>
<tr><td>Zhongyuan Dahua</td><td>Puyang</td><td>1800</td><td>142,000</td><td>Methanol</td><td>2008</td></tr>
<tr><td>Kaixiang</td><td>Shandong</td><td>1000</td><td>71,500</td><td>Methanol</td><td>2008</td></tr>
</table></td><td>Will make changes.</td></tr>
<tr><td>8.38
+</td><td>Page 196: Disadvantages: Syngas cooler plugging has not occurred at the Dutch plant. Syngas cooler fouling is controlled by mechanical rappers. Not sure those should be listed as disadvantages.</td><td>Will note that this is the case currently.</td></tr>
<tr><td>8.39
?</td><td>Page 199, Exhibit 3-78: The Oxygen/Coal and Steam/Oxygen ratios are significantly higher than those used when gasifying Illinois coal at SCGP-1. According to the final EPRI report on SCGP-1, the O_2/dry coal ratio was 0.79 instead of 0.85 used in Case 4, and the Steam/O_2 ratio was 0.064 instead of 0.125 used in Case 4. I would recommend lowering both the steam/oxygen ratio and the O_2/coal ratio.</td><td>Response in progress.
Where did our s/coal and o2/coal ratios come from? This is the kind of stuff that should be referenced.</td></tr>
</table>

No.	COMMENT	RESPONSE
	The temperatures and pressures of the streams #8a and 9a are illogical. Coal enters the dryer at ambient conditions and leaves at 1 atm pressure and perhaps 220ºF.	
8.40 ?	Page 200, Exhibit 3-78. It does not seem right that the Shell process would produce more acid gas than the E-Gas process when both are using an amine based AGR. Shell will have less CO_2 in the syngas and therefore less CO_2 should be captured. It appears the contractor has assumed virtually all of the CO_2 is captured by the Sulfinol-M process, but Sulfinol-M, as opposed to Sulfinol-D, is a partially selective solvent and will allow some of the CO_2 to slip through with the syngas.	Response in progress.
8.41 ?	Page 208, Gas Scrubbing: Exhibit 3-76 says the dry solids removal operates at 500ºF, but this text says the syngas exits the filter at 395ºF.	Response in progress
8.42 ?	Page 209, AGR: The CO_2/H2S ratio should not be greater than 5 for the Shell process when gasifying Illinois coal. Also, the text says a COS hydrolysis unit is needed if clean syngas sulfur spec is 10 to 20 ppmv, but spec is 30 ppmv for this design. Doesn't seem to make sense. In last paragraph, DOE needs to check with Shell to see if the statement that the Sulfinol process removes essentially all of the CO_2 is true. I believe Sulfinol-M will allow a sizeable fraction of the CO_2 to slip through.	Response in progress.
8.43 ?	Page 222, Exhibit 3-85: • Line 4.1: Previous studies have not shown Shell's gasifier/Syngas cooler to be so close to the E-Gas and GE in cost. Does this cost reflect the use of MP steam heat recovery in the syngas cooler rather than HP steam? • Line 8: Why is steam turbine cost less than Case 3 when steam turbine output is more?	Response in progress
8.44 ?	Page 223, Exhibit 3-86: Does maintenance material cost reflect the fact that Shell does not need to periodically rebrick the gasifier while the other two technologies do? Why is the water cost more than twice that of Case 3 when Exhibit 3-79 sows total raw water usage at 7742 gpm for Case 5 versus 7016 gpm for case 3?	Response in progress.
8.45 ?	Page 227, Exhibit 3-89: Why is dilution N_2 flow less than in Case 5? Why is moisture level of saturated syngas less than Case 5?	Response in progress.

No.	COMMENT	RESPONSE
8.46 ?	Page 250, Exhibit 3-96: • Line 8: Why does steam turbine cost more than Case 4 when steam turbine output is less? • Line 11. Why is accessory electric plant $23 million more than Case 5? Compare to E-Gas cases in which capture case accessory electric plant is $1 million LESS than non-capture case – GE case shows $6.5 million increase between non-capture and capture case.	Response in progress.
8.47 ?	Page 259, Line 6.1: There is a need to explain why GT costs more for GE cases than the other cases. I assume the cost of the syngas expander must be included in this line item.	Response in progress
8.48 ?	Page 264, Line 13: Improvements to site should not be less than the non-capture case.	Response in progress.
8.49 ?	Page 265: Initial cost of the Selexol solvent seems way too low. Should not be 2.2 percent of annual replacement costs!! Similar comment applies to initial AGR solvent costs of all 6 cases.	Response in progress.
8.50 ?	Page 266, Line 2.3: Why is there zero cost for materials? In GE case the materials cost of line 2.3 is $5 million.	Response in progress.
8.51 ?	Page 267, Line 5A.2: I would expect the sulfur plant to cost more than Case 1 because the flow rate of acid gas to the Claus plant is significantly greater in Case 3.	Response in progress.
8.52 ?	Page 269: I'm surprised that the maintenance materials for Case 3 are $5.7 million less than Case 1. Case 3 requires replacement of the dry solids removal filter elements every year at a cost of circa $2 million. Case 1 does not.	Response in progress.
8.53 ?	Page 274, Line 2: The cost difference between the Shell and E-Gas feed prep areas is striking.	Response in progress.
8.54 ?	Page 275: • Line 5A.2 should be more than Case 1 due to larger acid gas flow rate. • Line 5A.6 should not be more than twice the E-gas case as I would expect more solids loading on the E-gas filters than the Shell filters since E-Gas is injecting slurry to quench the syngas while Shell is recycling solids free syngas.	Response in progress
8.55 ?	Page 269: Why is Case 3's maintenance labor $3.9 million/yr less than Case 1? I would expect them to be fairly similar.	Response in progress.

No.	COMMENT	RESPONSE
8.56 ?	Page 277: Shell's maintenance materials are $2.5 million/yr more than Case 3, yet Shell does not need to replace gasifier refractory, replaces dry solids elements less frequently, replaces feed injectors less frequently and does not need to replace mill rods. Seems to be based strictly on a percentage of initial cost rather than an actual maintenance budget.	Response in progress.
8.57 ?	Page 279: • Line 8.3: Why is condenser cost $1 million more than Case 4 when condenser duty is 15 percent less? • Line 9.1: Why is cooling tower more expensive than Case 5 when condenser duty is less? Cooling tower of E-Gas capture case is less than non-capture case.	Response in progress.
8.58 ?	Page 294: CO_2 compressor efficiency is 75 percent. Was same efficiency used for IGCC cases?	Response in progress
8.59 ?	Page 325, Exhibit 4-13: Why is the cost of the coal handling system 17 percent less than Case 1 when as recv coal flow is 2 percent more. What is in IGCC coal handling equipment cost more than PC coal handling equipment?	Response in progress.
8.60 ?	Page 326, Exhibit 4-14: Water cost is $1,847,000/yr, which is 41 percent less than Case 1. Raw water use is 10918 gpm, which is 24 percent more than Case 1. Either the water cost or the water usage numbers are wrong.	Response in progress.
8.61 ?	Page 353, Exhibit 4-23: Water cost is 17 percent less than Case 9, but water usage (Exhibit 4-18) is 15 percent more than Case 10. Another set of inconsistent data.	Response in progress.
8.62 ?	Page 381, Exhibit 4-35, Line 9: Cooling water cost is same as Case 9, but condenser duty is 11 percent less.	Response in progress.
8.63 ?	Page 408, Exhibit 4-44, Line 9: Cooling water system cost is more than Case 11, but condenser duty is 17 percent less.	Response in progress.
8.64 ?	Page 445, Exhibit 5-8: Thermal effcy of 50.6 percent seems low for an F-class CC.	Response in progress.
8.65	Page 459, Exhibit 5-12, Line 6.1: CT costs $42 million less than IGCC CTs?	Response in progress.

No.	COMMENT	RESPONSE
9. Comments – Set 9 [NH]		
9.1	Overall it is a very impressive work. The use of ASPEN Plus to develop mass and energy balances is a good approach.	No response required.
9.2 +	The report seems to assume that all of the H_2S removal technologies are interchangeable. The report assumes 99+ percent removal for all three of the H_2S removal technologies that were considered (Selexol, MDEA, and Sufinol-M). However, I was under the impression that there are trade-offs with these technologies. As I understand it, the MDEA is considered to be the least expensive option – but the removals that I normally see reported are 98 - 99 percent. The Selexol process is more expensive but provides a higher H_2S removal (99+ percent). Some utilities have argued that including an SCR for NO_x control is only possible when using the Selexol process (or equivalent or better – such as the Rectisol process). I think some rationale for the choice of H_2S removal technology should be provided with each case. MDEA seems to be the preferred choice among the utilities that I've spoken with – both for cost and as an excuse for not installing an SCR.	An explanation was provided for the AGR process selections, but it will be expanded further. The team should meet with OSAP to discuss whether or not the AGR technology selections should be changed tp be consistent.
9.3 -	If the Selexol process is used for H_2S removal, then SCR can be used for NO_x control. There should be some rationale given for why SCR is not applied when technically feasible.	Technologies applied were based on BACT. This issue would go away if MDEA was used in non-capture cases.
9.4 -	I was originally surprised by the fact that a baghouse was chosen for PM control in the combustion cases. Only 10 percent of the current capacity uses fabric filters for PM control and those tend to be on smaller units. However, I see in Table 2 of the EPA/ORD Mercury White Paper that all of the new construction through 2020 is projected to be [SCR + FF + wet FGD]. So, maybe this is a reasonable assumption. This assumption greatly affects mercury control, however. The assumed 3 lbs of activated carbon injected per 10^6 cu-ft of flue gas would be very modest for a bituminous coal-fired boiler with a CS-ESP.	All new plant construction is using fabric filters. Make sure Jim Murphy is consulted on design of Hg control.

No.	COMMENT	RESPONSE
10. Comments – Set 10 [SK]		
10.1 -	Executive Summary, Page 1, Second Set of Bullets: Fuel availability is another important factor in the selection of the new generation technology.	Reflected in fuel prices.
10.2 -	Executive Summary, Page 2, Exhibit ES-1: Selection of the Selexol system for Case 1 (GEE Radiant Only) is a questionable choice, since the existing IGCC plants use MDEA technology and since no SCR is being used to justify extra costs associated with a Selexol system.	Our sources indicate chemical solvents are preferred when syngas pressure is less than 400 psi. We're significantly over that pressure. Same comment as 9.2
10.3 -	Executive Summary, Page 3, Exhibit ES-2: The efficiency of the GEE Radiant IGCC case (Case 1) appears to be low, especially in comparison with the supercritical PC case (Case 11), when the data reported by others is considered. Also, this IGCC efficiency is below that reported for the Wabash and the two European IGCC plants.	Shouldn't compare efficiencies with European IGCC plants. Efficiency is as calculated for this case. It is worrisome that the efficiency is lower than that for Wabash. Investigate and confirm performance is correct.
10.4 +	Executive Summary, Page 9, Exhibit ES-6: The CO_2 emission rates listed in lb/MWh for the various cases are too low. The actual rates should be about double the rates listed.	Will make the change.

No.	COMMENT	RESPONSE
10.5 +/-	Exhibit 2-5, Page 18: Please note the following comments: • SCR should be added as one of the NOx control technologies used for PC plants. • It does not appear that LNB (as listed) is available for the gas turbines used in the IGCC service. Also, Exhibit 1-1 lists only N_2 dilution as the NOx control technology used for IGCC plants. • "Sulfur Limits" should be replaced with "SO_2 Limits." • For the high-sulfur coal PC application, a new plant would most likely be required to add a wet ESP for the control of SO_3. It is also possible to add sorbent injection for SO_3 control; however, the trend as reflected by recent air permits is to add a wet ESP. This should be reflected in this report. • For a bituminous coal-fired PC plant, a PAC injection system may not be required for Hg control, because of the Hg removal expected in a plant that is equipped with SCR and a wet FGD system. Addition of a wet ESP would result in further removal of mercury. These facts should be clearly highlighted in the report, even though a PAC injection system has been included.	Will fix – didn't convert from Word to PDF. Will verify. Sulfur is ok (99+% refers to H2S) List as H2S This is counter to the permits we reviewed for the PC/IGCC baseline exercise. Reference this info when describing sulfur control. Study assumed no co-benefit capture. See comment 3 in guidance document

No.	COMMENT	RESPONSE
10.6 -	Exhibit 3-20, Page 66: A controlled SO_2 emission rate of 0.01 lb/MMBtu reflects a reduction efficiency of approximately 99.8 percent, taking into consideration a 2.51 percent sulfur content and 11,666 Btu/lb heating value of coal. This appears to be too high a reduction efficiency, even for a Selexol system. Is there experience out there that supports this?	Any of these results and/or assumptions are just projections based on the data available. This available data should be reference to provide justification for assumed performance. It appears as though this level is possible, but each plant will have varying designs. It is also possible that the reference plant designs for each gasifier vendor will fall short of this to avoid surpassing regulated emissions levels by this much.
10.7 +	Exhibit 3-20, Page 66: The CO_2 emission in lb/MWh does not match that reported in Exhibit ES-6.	Same as 9.4 – will fix.
10.8 ?	Exhibit 3-20, Page 66: The lb/MWh figures are presently based on the plant net output. These should be based on the plant gross output, to be consistent with the way these limits are defined in the air permits and the way they have been defined in the EPA's NSPS standards.	In process of investigating this.
10.9 +	Page 66, Second Paragraph: In this paragraph, 30 ppm of SO_2 in syngas is equated to less than 5 ppm in flue gas. On page 32, last paragraph, the same 30 ppm is equated to 2 ppm. Using the same conversion factor used in this report to convert 15 ppmvd of NOx at 15 percent O_2 to 0.052 lb/MMBtu of NOx, the SO_2 emission at the stack should be approximately 2 ppmvd at 15 percent O_2. The report should be listing the actual numbers for the emissions. This comment applies to other places where similar information is provided.	Same issue as 5.17.

No.	COMMENT	RESPONSE
10.10 ?	Page 66, Second to Last Paragraph: It would be helpful if an explanation could be provided as to why a quench/scrubber is used for particulate control for this IGCC case as opposed to a cyclone and a filter.	Response in progress.
10.11 +	Page 81, Account 3, Equipment No. 6: To be consistent with PC and NGCC cases, the steam rating of the auxiliary boiler should be provided.	Will make change.
10.12 -	Exhibit 3-29, Page 89: A process contingency has not been used for any of the plant configurations included in this report. Shouldn't the process contingency be applicable to some of the technologies (not necessarily for this case)? This is especially true for the IGCC plants, when they are being compared to the well-established PC and NGCC technologies.	This was explained in the cost methodology section of the report. This should be changed according to guidance document.
10.13 ?	Exhibit 3-54, Page 138: Considering the coal sulfur content and heating value, a controlled SO_2 emission rate of 0.003 lb/MMBtu means an SO_2 reduction efficiency of 99.93 percent. It also means an emission of less than 1 ppmvd at 15 percent O_2. Can such effectiveness be justified for an MDEA system, which is expected to be less effective than a Selexol system?	Response in progress.
10.14 ?	Exhibit 3-80, Page 202: Same comment as *#10.13*.	Response in progress.
10.15 -	Section 4.1.5, Page 287: Please see *#10.5* on mercury controls.	See comment 9.5.
10.16 ?	Page 295, Last Paragraph: Provision of only one 100 percent boiler feed pump appears to negate the requirement for a highly reliable plant. For a large plant of the size provided, two 50 percent pumps would appear to be more appropriate.	Response in progress.
10.17 +	Exhibit 4-6, Note B, Page 302: All of the information provided in various earlier exhibits show use of a wet FGD system only for SO_2 control (e.g., see Exhibit 1-1). What is this polishing step? Achieving less than 10 ppm of SO_2 emission appears to be a quite difficult task for a PC plant. This part of the system should be described and examples should be provided as to where it has been used.	Same as comment 5.42. Consult with Jim Murphy

No.	COMMENT	RESPONSE
10.18 +	Exhibit 5-9, Page 446: The SO_2 and particulate emissions from NGCC plants are not "nil," which implies zero emissions. (Exhibit 5-7 should also be showing a typical SO_2 content of pipeline natural gas.) The air permits generally carry both SO_2 and PM emission limits for NGCC plants. The SO_2 limit may run from 0.0005 to 0.0007 lb/MMBtu and PM limit from 0.005 to 0.01 lb/MMBtu. Exhibit 2-5 in this report does list emission targets for both SO_2 and PM. However, it may be appropriate to show the PM and SO_2 emissions as negligible (more appropriate than "nil").	Will use negligible instead of nil.`

No.	COMMENT	RESPONSE
11. Comments – Set 11 [TGK]		
11.1	**Overall:** As an academic modeler of advanced energy conversion systems, whose primary source of information comes from detailed papers and technical reports in the public domain, I applaud NETL for publishing this ambitious study (and its forthcoming companion volumes). Its level of detail/disaggregation, particularly economic, is uncharacteristically high, potentially making it an exceptionally useful reference document for the research community. Such a high level of detail ensures that it will be subjected to numerous modeling studies, for the purpose of both validation and extension to new concepts.	No response required.
11.2	**Introduction:** The primary focus of this study – electric power production with and without CO_2 capture – is both understandable and appropriate given the historical interest of the U.S. gasification community and DOE, which has focused primarily on IGCC in the United States. The comparison between IGCC and PC systems (with and without CO_2 capture) enables researchers and policy makers to understand to what extent future constraints on CO_2 emissions (or carbon taxes) might make IGCC an economical alternative to PC. However, given the many barriers to entry for new plants and new technologies in the power markets, and the historically high cost of natural gas and crude oil, I wonder if the best opportunities for coal gasification with CO_2 capture do not lie instead with the production of synthetic natural gas and liquid transportation fuels. I note that in a forthcoming Volume 2 you plan to examine the former of these two options. The choice of plants seems reasonably comprehensive, at least to the extent that one is trying to understand the thermodynamic and economic competitiveness of the three primary commercial entrained flow gasifiers – versus each other and various PC configurations – in a world where carbon constraints loom large. But I wonder about this particular packaging of information, and find myself asking: “Who is the audience for this work?” and “What do the	No response required.

No.	COMMENT	RESPONSE
	authors hope they will get out of it?" The level of technical detail is, in places, sufficiently high that a system modeler could reproduce both the thermodynamic performance (e.g., in Aspen Plus) and economics (in Excel) of each plant. At the same time, the whole package seems to me a bit pro forma, and has a number of significant defects that I will discuss below. Before I delve into specific comments, most of which are critical rather than laudatory (I have left out the hundreds of instances where praise was due), let me note at the outset that all of the defects that I point out below can easily be remedied. Once again, I congratulate both the authors and DOE on undertaking such an important endeavor as this study and its clear reporting.	
11.3 -	**Lack of Context:** This study does not arise out of a vacuum. Rather, it is the latest in a long, long line of similar studies on electricity production via coal IGCC and PC, with and without CO_2 capture. How does this work fit into those others? How does it better them, or complement them, or contradict them? I know, from personal experience, that it is often difficult or impossible to reconcile one's results with those that have previously appeared in the literature. But, the attempt is nevertheless very instructive for the both the authors and readers. For instance, in addition to the myriad of EPRI reports on IGCC, DOE itself has published a number of similar studies. Two that come to mind are NETL's IGCC "Base Case" studies by Shelton and Lyons (Ref. 1), and the Dec. 2000 EPRI/DOE/NETL study "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal" by Parsons et al. (Ref. 2). What is the relationship between this work and those earlier efforts? How is the approach different? How do the results differ? What does this study tell us that those did not? For example, this study purports to tell us that the CoP E-Gas technology has the lowest installed capital cost and lowest cost of electricity (COE) of the three IGCC systems considered. On its face, that result appears to contradict a number of recent studies compiled by EPRI (e.g., Ref. 3), but there is no mention of this discrepancy, or its potential resolution. Rather, the results here are simply presented essentially without comment, as though to say, "Make of them what you will." In general, a scientific paper cannot be published in a peer-reviewed journal if it fails to include a clear discussion of the relevant work that preceded it, with appropriate citations. The	Again, not comparing to other studies was done intentionally. We can reference other studies if appropriate, but

No.	COMMENT	RESPONSE
	reason, of course, is because such information is very important in moving the field forward. It forces the authors to create something worthwhile, instead of just tossing another paper in the great bin of the open literature. It tells the readers where the research fits into the complex tree of discovery (and false steps) – and it highlights the particular innovations offered by the study. In contrast, techno-economic studies of power plants created by engineering consulting firms often do not have such descriptive, useful information. Rather, they are frequently loaded with numbers – e.g., capital cost estimates – that are unjustified and unexplained, often purposely obscured, presumably to protect intellectual property. To its detriment, this study tends more toward the latter (consultant reports) than to the former (peer-reviewed papers). However, this defect is unnecessary, and can be rectified. The authors obviously need not reveal their proprietary capital cost estimation algorithms, but they should discuss the conceptual basis that underlies each plant design. Also, they need to discuss how their results compare with the results of previous studies. Without such information, both the utility and credibility of the study are markedly reduced.	wasn't the intent to make comparisons. Must do more work to reference sources for performance and cost when available or appropriate.
11.4	**Lengthy, but Information Starved:** Despite its significant length, I find this report surprisingly, and disturbingly, lacking in useful information. This is a major DOE report on a subject of national and global importance. As much as possible given IP restrictions, it should be clear, transparent, and reproducible. But, so much of the data is lacking. So many of the streams are missing. The entire bottoming cycles are missing. Heat integration is missing. Sour and black water processing is missing. The ASU is missing. And, *of course*, gasification and AGR are missing – despite the fact that these, too, have been pretty accurately modeled for decades in the open literature. (And the stream tables that do exist include density instead of enthalpy!) Even the previous NETL "Base Case" IGCC reports (see, for example, Ref. 1) are more complete than the IGCC's in this study. Why are we going *backward* in our level of clarity and transparency? When I publish a paper, at a minimum I provide a table below of basic modeling assumptions about plant components: compressor efficiencies, pressure drops through reactors and heat	Gasifier stream data were considered proprietary. Overall M&E balances given in tables and figures. ASU is modeled as a black box so no internal stream data are available. Sour and black water processing are not modeled. The reviewer correctly points out that we must maintain a level of clarity

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	exchangers, heat losses, pinch *ΔT*s, intercooler temperatures, etc. And then, when there are interesting deviations from these general rules, I discuss it in the text. There is *nothing* like that in this report. What is provided is a mind numbing recitation of vague facts and properties. Often the same information is repeated again and again and again, in section after section. It is not as though adding a full set of stream diagrams and tables would take up too much space; there is so much space that could be saved by removing repeated information. [Exhibits 3-23 through 3-27 are tantalizingly helpful, except that: 1) they exist for only one of the IGCC cases, 2) even that set of diagrams is incomplete, 3) they are almost impossible to read, and 4) they do not have accompanying stream tables.] For example, each gasifier has pages and pages of items in the Major Equipment List. But honestly, little of this information is very useful. How about throwing out the Equipment Number, and adding the capital cost estimate for each piece? How about adding more detailed notes as to the dimensions and performance of those items? Since 95 percent of the lists are identical between paired cases 1&2, 3&4, and 5&6, why not combine them, thereby highlighting the differences rather than making the reader page back and forth to see what is different between the cases? Same, too, for the results; pair them to save space and increase the intellectual content. Same also for the process diagrams; the author certainly does not need to show the same overly simplified schemes twice, with only minor modifications between them. The point is that this study has the potential to be a fantastic reference document! In its current incarnation, however, it is needlessly far from that. There are many, many terrific IGCC studies out there (many EPRI reports come to mind, e.g., Refs. 4 and 5); why can this not be one, too? Further space- (and brain-) saving strategies: Put a (complete) description of dual Selexol AGR up front in Section 3.1 and refer back to it rather than writing out the description twice, half-heartedly. Do the same for CO_2 compression. Why is so little information presented about one of the biggest new parasitic loads (when moving from CO_2 venting to CO_2 capture)? A compilation of CO_2 compression costs ($/ton from atmospheric to 150 bar) in the open	and transparency that will make this piece of work most valuable and useful. It is a good idea to list basic modeling assumptions as listed by reviewer at end of this comment….and this would also make good info for the informal documentation for the ASPEN models. This is more detail than we intended to provide. The repetition was provided to make each section stand on its own. Equivalent exhibits are being prepared for all IGCC cases. Meant to be printed on 11x17 paper. Stream data are on the drawings

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	literature shows a range of well over an *order of magnitude*! (What is the compressor type and configuration? How many stages? What efficiencies? What portions are acid-resistant? What are the details of the dehydration system?) This report would have one believe that the issue is so pedestrian that it is not even worth mentioning. Why does this report not have a consistent set of units, for example, temperature in Celsius and pressure in bar, with English units in parentheses?	Again – stand alone sections. Compression details beyond the scope of this study. All technologies assumed to be commercially available. This was done consistently throughout.
	Assumptions Adopted For Performance Calculations ***Gasifier:*** Operating conditions: 70 bara, 1038 C. Slurry water/raw coal weight ratio: 2.3. Cold gas efficiency: 87.3 percent HHV. Heat loss: 0.005 of the coal LHV thermal input. Carbon conversion: 99.2 percent ***Syngas coolers:***	

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	Heat losses: 0.007 times heat released by the hot stream. Pressure loss: 2 percent. Ash discharge temperature: 350˚C. Outlet temperature: 250˚C.	
	Air separation unit (ASU): Power consumption: 0.261 $kWh_{el}/kg_{PURE\ O2}$. Oxygen composition: 95 percent O_2, 1.4 percent N_2, 3.6 percent Ar	
	O_2 and H_2 compressors: O_2 outlet pressure: 84 bara (1.2 times the gasification pressure), H_2 outlet pressure: 60 bara. Number of intercoolers set so that stage output temperature <200˚C. Isentropic efficiency: 0.85. Organic/electric efficiency: 0.94 Temperature at the cooler exit: 35˚C. Pressure drop in the intercoolers: 0.01	
	CO_2 compressor: 4 inter-cooled stages. Compression ratio/stage: 3.5. Isentropic efficiency: 0.82. Final pump efficiency: 0.75. Temperature at intercooler exits: 35˚C. Pressure drop in each inter cooler: 0.01. Pressure drop drying intermediate dehydration process: 0.01	
	High temperature WGS reactor: Pressure drop, $\Delta p/p$: 2 percent. Inlet S/C ratio 0.7-3. Heat loss: 2 percent of the WGS heat release.	
	Assumptions Adopted For Performance Calculations (cont'd)	
	Hydrogen Membrane Separation Reactor (HMSR): Pressure drop, $\Delta p/p$: 2 percent. Heat loss: 0.02 of heat released in the shift reaction. H_2 backpressure: 2 bar.	
	Heat exchangers: Heat losses: 0.007 times heat released by the hot stream. Pinch point for heat recovery steam generators: 8˚C. Subcooling at economizer outlet: 5˚C. Minimum ΔT for gas—liquid heat exchangers: 10˚C. Pressure loss: 2 percent.	
	Pumps: Hydraulic efficiency: 0.75. Organic/electric efficiency: 0.94. For cooling media pumps, electric power consumption is 0.01× heat power released.	
	Raffinate combustor: O_2 flow rate: 1.05× stoichiometric. Pressure loss: 0.03. Heat loss: 0.005× the raffinate LHV.	

No.	COMMENT	RESPONSE
	Raffinate turbine: Un-cooled TIT: 850˚C, cooled TIT: 1250˚C. Organic/electric efficiency: 0.975. Efficiency calculated by the model for un-cooled turbine from ~ 70 bar is equivalent to 0.88 polytropic (or 0.919 isentropic). ***FGD:*** Inlet gas temperature: 160 C. Maximum temperature of recoverable heat: 50 C. SO_2 removal efficiency: 0.90. FGD also and produces CO_2 at mass rate 0.6875 times the SO_2 removed (mol rate = 1× the SO_2 removed).	
11.5 NETL	**Lack of a Narrative:** As I mentioned above, this study springs from a rich history of experimental, developmental, commercial, theoretical, and numerical work in this field. Real people spent real time doing this study, and yet it hardly shows. Choices were made about plant configurations, components, modeling assumptions, etc. Yet the reader learns hardly anything about the considerations behind those choices. The document hardly has any life at all. (Section 3.1 might have a slight pulse, but it is very hard to find.) Compare this report to similar works by the IEA Greenhouse Gas R&D Programme. The first 80 pages of their May 2003 analogous study on IGCC with CO_2 capture (Ref. 6) contains a much more significant discussion of the real issues at hand. In contrast, this study simply presents spare descriptions of what was done, but no whys and why nots. Consider the IEA Greenhouse Gas R&D Programme Report PH4/27, "*Canadian Clean Power Coalition Studies on CO_2 Capture and Storage*" (Ref. 7), which describes the original goals for the program, and changes that were made in the study's direction and focus as the results began to emerge. Or, take a look at the Fluor Daniel/IEA "*CO_2 Capture via Partial Oxidation of Natural Gas*" (Ref. 8), which handles (obfuscates?) a lot of proprietary information while at the same time clearly investigating and discussing many of the critical design issues. This *can* be done well! A few examples. Why were the particular gasifier pressures chosen, and what are the implications? Why was gasifier sparing not considered carefully? Numerous studies (e.g.,	This comment will require discussion about how to address. The whys and why nots should be described. The report is missing this valuable insightful information. The reviewer correctly points out that the report lacks discussion on critical design issues.

No.	COMMENT	RESPONSE
	Refs. 3 and 6) indicate that of the three gasification technologies considered in this study, only Shell is able to achieve an availability of 85 percent without a spare gasifier. The slurry fed, uncooled gasifiers are not able to achieve even 70 percent availability in a single gasifier configuration. Why was the GEE radiant+quench configuration chosen over a straight quench? Excellent studies (e.g., Ref. 4) have looked at just this question in great detail; they conclude that radiant and convective coolers are generally not economical. Why then is the radiant+quench configuration used for GEE's "Reference Plant" design? What are the competing considerations? Why is the Shell IGCC with CO_2 capture configured so much like the case without CO_2 capture? The notion of a partial water quench – where water/steam instead of clean, cooled syngas is used to cool down the raw syngas to just above its dewpoint…supplanting the very expensive syngas cooler and obviating the huge syngas recycle loop (and its compression) – has been promulgated by EPRI for years, and makes even more sense when water gas shifting for CO_2 capture lies downstream. Why was this configuration not considered? Questions like these are part of what makes this field interesting.	

No.	COMMENT	RESPONSE
11.6 NETL	**Lack of Thoughtful Analysis:** This report feels to me like it was put together because it was required, rather than because it was really trying to communicate critical new information to colleagues in the field of coal gasification and power generation. The IGCC section of the report is a comparison between three key technologies whose costs and performances are different for some very important reasons. But none of that is teased out or discussed. Instead of highlighting the complex tradeoffs inherent in the quest for low COE and low CO_2 emissions, as discussed, for example, in Neville Holt's "*Gasification Process Selection – Trade-offs and Ironies*" (Ref. 9), this study simply recites – over and over again – the basics of IGCC design, as one might find in the 1993 SFA Pacific "Gasification Guidebook" (Ref. 10). It makes me wonder again: "Who is the intended audience of this report?" For example, the second stage of CoP's E-Gas technology, which confers many advantages to the system, is also the cause of its relatively low pressure (in the "iron cross" configuration, anyway) and its difficulty in achieving high levels of CO_2 capture. Is this mentioned in the report? No. But we do learn that the front loader has rubber tires, and the HRSG drums have sight glasses for monitoring the water level, and the ASU has suction filters, etc. Sigh. COE is blithely plotted as a function of capacity factor, from 60 percent to 100 percent. A *100 percent* capacity factor, without equipment sparing, and without considering gasifier sparing! This is just not thoughtful analysis. Specifying high availability is not just cranking the *capacity_factor* variable in the economics spreadsheet, but instead requires careful – and well documented(!) – consideration of what significant changes in equipment and operating procedures are required. And these issues change with different gasifiers. (A case in point. The incredibly high availability achieved by Tennessee Eastman's Kingsport Texaco-based coal gasification system is the product of a myriad of operational and equipment procedures that are not followed by the relatively low availability Texaco gasification system at Polk Power Station. However, both approaches are well motivated by the economics of their respective operating environments.) Earlier, I mentioned the idea of combining equipment and cost tables for paired IGCC cases. Why not combine tables for all gasifiers, to highlight the similarities and differences between them? But don't just make the tables, *look* at the tables and draw inferences, and ask	So many issues are raised here that additional discussion will be required. The report should include discussions such as those highlighted to the left.

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	interesting, leading questions. Suggest new approaches, new questions that need to be addressed. In short, in addition to needing a detailed Introduction section, this report also needs a substantive Discussion section, and a real Conclusion section. Each of the gasification systems has unique advantages and disadvantages. They lead to different performance in different situations, to stratification in the market, to niche positioning. These issues are touched on – glossed over – very briefly. The competition between these – and other – gasifiers is a really interesting and important issue, one that requires careful consideration, not cookie-cutter designs. I find the comparison between coal-based plants and natural gas-based plants largely fatuous. Too compare their COEs is to suggest that they are competitive in ways that they are not. They are vastly different plants. Just looking at their footprint – both physical and environmental – amply shows that. Their economic characteristics (i.e., capital vs. operating costs) are totally opposite; considering their relative "dispatch" costs gives a completely different picture of their relative economic merit. They naturally occupy *different* niches. I believe that analyses that compare CO_2 venting plants with capture CO_2 plants must explicitly consider the prospective costs of CO_2 storage. It significantly alters the relative economics of the plants, especially when comparing coal-based plants with gas-based plants. Similarly, I believe that not to include a carbon tax of some sort is to completely miss a critical element of the story. CO_2 capture plants will only come to exist in an environment that rewards (economically) superior environmental performance. Not adding a carbon tax sufficient to motivate the construction of these plants is to miss a critical element of the economics. Both of these additions are messy, but important in reaching accurate conclusions. In addition, calculating the cost of avoided CO_2 as the difference between two plants of similar design, one with CO_2 capture and one without, is the simplest but least realistic of all possible scenarios. The cost of avoided CO_2 is calculated from the difference between the best CO_2 capture plant that you can build at a site, and the best CO_2 venting plant that you would build	

No.	COMMENT	RESPONSE
	otherwise, feedstock notwithstanding. And either of these two options could be a re-powering or a retrofit. Constraining them to be of the same type of greenfield plant yields just one minor, largely irrelevant, bit of information.	
11.7 NETL	**A Misleading Executive Summary:** I find the executive summary perhaps the most egregious section of the report. By lining the plants up, at a single capacity factor (or two) and single price for the feedstocks, the summary appears to provide clear results when, in fact, the situation is a lot more complicated. Summaries should shorten the story, but not hide or downplay the underlying uncertainties.	Again, this will require additional discussion, but we certainly don't agree with all points made. Are there some sensitivity curves that should be developed and included in the executive summary ?
11.8	**My Conclusion:** This study contains all the components to be really fantastic. The authors need only approach the report with the idea that they are in a conversation with the rest of the world about a subject of great importance, and thoughtfully engage with us in a manner that will help these plants come on line as soon as possible. Bravo for a fine piece of work!	No response required.
11.9 +	**Specific Comments:** Page 1: Fuel costs ($/MMBtu) should specify that they are on a high heating value (HHV) basis. In the U.S., this is a given, but in Europe, fuel is (more appropriately) priced on its lower heating value basis.	Will make change.
11.10 +	Page 3: The Y-axis in Figure ES-2 should specify that the plant efficiency is given on a (HHV) basis.	Will make change.
11.11 +	Page 4: The Y-axis in Figure ES-2 should specify that the plant efficiency is given on a (HHV) basis.	Will make change.
11.12 ?	Page 20: The method for calculating the cost of avoided CO_2, as formulated on page 20 (as presented on page 254) is not a particularly good one.	Comment incomplete.
11.13 -	Page 30: Why beat around the bush here? Why not tell us the key temperatures and pressures in the ASU model used in these studies? How about some stream data?	ASU wasn't modeled.

No.	COMMENT	RESPONSE
11.14 +	Page 34: The ordering of paragraphs and ideas in this section is a bit mixed. Paragraph 3 ("There are well over 30 AGR processes…") clearly should not be *within* the section entitled, Chemical Solvents.	Will make changes.
11.15 +	Page 35: Citing a "good" steam consumption value (0.8 to 0.9 pounds per gallon of liquid) seems pointless without mentioning the pressure or temperature of the steam.	Will add steam conditions used in the study.
11.16 +	Page 35: In the physical solvent section, I would point out that AGR systems based on physical solvents become increasingly economical – and eventually economically superior to amine capture – as the partial pressure of CO_2 in the synthesis gas (and thus total system pressure) increases.	Will make change.
11.17 -	Page 36: Since Exhibit 3-4 is almost exactly identical to Exhibit 3-3 (except for the flash and recycle loop), I would either get rid of one of them, combine them, or make the figures more realistic (e.g., in Exhibit 3-4, add multiple flashes). In fact, I would talk more about the recycle loop.	These are generic configurations – such detailed discussions are not warranted.
11.18 +	Page 36: I would mention another advantage of physical solvents, which is that CO_2 is flashed off at various pressures, which reduces the compression work and parasitic power requirements.	Will make change.
11.19 -	Page 38: (I mention this elsewhere) You mention the two stage Selexol absorption in a single line. I would shorten and simplify the report by describing the system completely in this section, and referring to the description in later sections.	If we do this, the sections won't stand alone. Leave alone
11.20 +	Page 42: You give no good reason for handling tail gas treating differently in various cases. Is it for your own convenience (e.g., you happened to have different data on hand for different systems), or is there a good reason to do so?	Will explain that these were vendor-agreed approaches and approaches used in prior designs.
11.21 ?	Page 42: In the CoP system, the Claus tailgas is hydrogenated and then returned to the gasifier. Why bother hydrogenating it? It is not as though the gasifier cannot handle a tiny slipstream containing a mixture of COS and SO_2. In fact, why not return the tail gas to the gasifier in all cases?	Response in progress.

No.	COMMENT	RESPONSE
11.22 NETL	Page 45: You do a nice job of explaining some of the issues associated with firing a gas turbine with low calorific value fuel, but fail to discuss the issue quantitatively. In your plant designs, do you adhere to a maximum fraction of H_2O in the turbine exhaust (to limit heat transfer to the buckets)? Or do you always saturate the fuel gas and add N_2 to make up any needed diluent? Do you reduce the firing temperature for when the concentration of H_2O becomes high, or the turbine mass flow increases (compared to natural gas firing)? By how much? Is the reduction in firing temperature correlated with the H_2O concentration?	See comment 4.71. GE has been generally non-supportive to date aside from the data that they gave us. Is it appropriate to try again?
11.23 -	Page 67: Is this not almost exactly the same description you gave on page. 61? Yikes! What is the point of this endless repetition of marginally useful information?	Idea is to make each case stand alone.
11.24 +	Page 76, Second paragraph under heading "Gasification": "Coal slurry is transferred from the slurry storage tank to the gasifier…" Did you not *just* say that in the preceding paragraph?	Will make change.
11.25 -	Page 77, First paragraph under heading "Acid Gas Removal": "A feature of this plant configuration is that H_2S is removed within the Selexol unit." Huh? That is a pretty common feature of *all* AGRs.	This was to distinguish it from Sulfinol and MDEA.
11.26 +	Page 77, Second paragraph under heading "Acid Gas Removal": How is the lean Selexol pre-loaded with CO_2 in this non-CO_2 capture case?	Will add text - just let the CO_2 build up in the solvent and tailor process conditions so that only H_2S comes off with regeneration.
11.27 +	Page 77: No COS hydrolysis is mentioned.	Will add to description.
11.28 +	Page 107: No mention is made of water gas shift reactors.	Will add to description.
11.29 +	Page 116: The CO_2 dehydration (absorption and solvent regeneration) unit is not specified. Is it not a unit that has significant size and cost?	Per the text, tri-ethylene glycol is used for dehydration. Costs included in compression costs.

No.	COMMENT	RESPONSE
11.30 -	Page 127, Bullet #4: Fire tube syngas cooler *with quench section at the outlet*? That does not seem likely.	It is a system that was suggested to us by GE on the NYPA project and I think it will be included in the GE reference plant design. The mechanics of doing such a thing are unclear as GE will not provide this type of detail. Reference this info from NYPA.
11.31 -	Page 131: It might be useful to discuss the issue of tar formation caused by the second stage chemical quench/low exit temperatures.	Beyond the scope of the study.
11.32 +	Page 131, Paragraph 6: "The key advantage of the CoP technology…" This does not seem to *me* to be the key advantage of this technology relative to the other two gasifiers. Both Texaco and Shell have ample full-scale commercial experience on bituminous coal, and Shell at least has the Deer Park tests (which are pretty impressive).	Will modify wording.
11.33 +	Page 145: No COS hydrolysis is mentioned.	Same as 10.28.
11.34 +	Page 171: No mention is made of water gas shift reactors.	Same as 10.29.
11.35 -	Page 167: Absolutely no comment is made on why the CO_2 capture fraction is significantly lower than the other two gasifiers (high methane content).	High methane content issue is discussed.
11.36 ?	Page 196: "The key disadvantages of the Shell coal gasification technology are the relatively high oxygen requirement and the high waste heat recovery…" That is not true; the former is *lower* for Shell than GEE or CoP because it is dry feed, and the latter is no worse than the others (well, maybe higher than CoP). Do you mean to be comparing Shell – or all oxygen-blown entrained-flow gasifiers – to other types of gasifiers?	Response in progress.

No.	COMMENT	RESPONSE
11.37 -	Page 196: "…the Shell gasifier employs a cooled refractor, which should require fewer changeouts that an uncooled refractory." This seems to be rather understated. How often is the refractory changed at Kingsport? How often at Buggenum? I think you are greatly downplaying the advantages of a slag-coated refractory.	Such details were beyond the scope of the study. If gasifier O&M costs reflect how often refractory is changed out, this should be described to show that it was taken into account. On the otherhand, if O&M costs and/or availability did not consider refractory life, they should be updated to include this.
11.38 -	Page 203: I am shocked to find that you have a carbon loss of 5.6 percent in the Shell system [(6.61+0.66)/130.2 tonnes/hr], as compared to 2.1 percent in the GEE system, and 0.85 percent in the CoP system. I have never seen that in any other report, most of which are *much* more detailed that this.	Syngas is combusted to dry coal which accounts for higher carbon loss. Check this….is syngas combustion used in other reports/studies? How does carbon loss compare to those?
11.39 +	Page 235: No mention is made of water gas shift reactors.	Same as 10.29.
11.40 +	Page 497: Some of the references are really incomplete or obscure, e.g., Refs. 2, 17, 18, 21, and 22.	Will attempt to clarify.
11.41	**Set 11 - References:** 1. *Shell Gasifier IGCC Base Cases*, W. Shelton and J. Lyons, NETL PED-IGCC-98-002, July 1998 (revised June 2000). 2. *Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal*, Buchanan T., M. DeLallo, R. Schoff. and J. White., EPRI, Palo Alto, CA, US DOE – Office of Fossil Energy, Germantown, MD and US DOE/NETL, Pittsburgh, PA, Interim report, 1000316,	

No.	COMMENT	RESPONSE
	December 2000. 3. *A Summary of Recent IGCC Studies of CO2 Capture for Sequestration*, Neville Holt, George Booras, and Douglas Todd, Proceedings of the Gasification Technologies Conference, San Francisco, CA, October 12-15, 2003. 4. *Cost and Performance for Commercial Application of Gasification-Combined-Cycle Plants*, Matchak T.A., Rao A.D., Ramanathan V. and Sander M.T., EPRI Report AP-3486, Apr. 1984. 5. *Engineering Evaluation of Prenflo-Based Integrated-Gasification-Combined-Cycle (IGCC) Power Plant Designs*, Sargent & Lundy, EPRI TR-101609, Final Report, November 1992. 6. *Potential for Improvement in Gasification Combined Cycle Power Generation with CO_2 Capture*, IEA Greenhouse Gas R&D Programme, Report PH4/19, May 2003. 7. *Canadian Clean Power Coalition Studies on CO_2 Capture and Storage*, IEA Greenhouse Gas R&D Programme, Report PH4/27, March 2004. 8. *CO_2 Capture via Partial Oxidation of Natural Gas*, Fluor Daniel, IEA Greenhouse Gas R&D Programme, Report PH3/21, April, 2000. 9. *Gasification Process Selection –Trade-offs and Ironies*, Neville Holt, Gasification Technologies Conference Washington, DC, October 4-6, 2004. 10. *Coal Gasification Guidebook: Status, Applications, and Technologies*, SFA Pacific, Inc., EPRI TR-102034, Electric Power Research Institute, Palo Alto, Ca., 1993.	

No.	COMMENT	RESPONSE
12. Comments – Set 12 [SST]		
12.1 -	We need a report on fossil energy technology for power generation. This report will serve this purpose well if more detailed process information is presented in a more organized fashion. DOE might want to consider using the format shown in the SRI PEP report or most of the EPRI report on IGCC feasibility study. The report seems to indicate that most of the engineering work was done using the ASPEN Model. Thus, detailed information must have been generated.	Not feasible to change the entire report format at this point in time.
12.2 -	I did a random check on some of the performance data for the six IGCC cases. Some of the results are shown in specific comments 10, 11, and 12. They are no mathematical errors. The calculations appear to be sound. However, my results seem to indicate that these six cases were not done on the same basis. That is, the results should have been more consistent if these cases were developed from scratch with the same process model and engineering approach. Of course, this should not change the conclusions. But, the authors might want to state this in the report.	Not sure what he is suggesting be stated.
12.3 +	Page 1, last paragraph states that "the general methodology was to use information provided by the technology vendors." Later in the same paragraph, it states, "performance and process limits were based upon published reports." There is a big difference in credibility between data from these two sources. The report should be structured so that readers can easily identify the sources of information presented in the report.	Will add clarifications. The reader should be able to easily identify sources of information.
12.4 -	This report provides a thorough introductory description for various commercially-available fossil-based power generation technologies. However, the results of each case are given without adequate supporting details so that the readers could not: • Extrapolate or interpolate the results for slightly different cases or scenarios, and • Validate the accuracies of the performance data and cost estimates.	Detailed cost and performance data are provided so that the accuracy can be checked.
12.5 -	The report should state whether the cost estimating methodology, economics analysis, etc., are consistent with NETL's Quality Guidelines for Energy System Studies and the Financial Model.	The methodology is described – comparisons to others is not warranted. In addition to stating this, the

No.	COMMENT	RESPONSE
		guidelines should be consulted and the model used if available (see John Wimer)

No.	COMMENT	RESPONSE
12.6 -	Most of the readers of this report would like to learn about the fossil energy power generation technologies and be able to apply the data for their specific applications. For each IGCC case, the presentation of the data and the process description are so incomplete that they are not useful to the readers. Some examples and recommendations are as follows: • There are 28 pages of general description of an IGCC plant (pages 27 to 51). After the presentation of the Case 1 flow diagram, material balance, and plant performance, the detailed plant description takes 3 pages (page 75 to 78). • Streams 8 to 12 are not shown because they are "proprietary". The reason given in page 61, 2nd to last paragraph, is hard to understand. If the gasifier exit temperature can be presented in the report (page 76, Raw Gas Cooling), "syngas composition that was calculated based on information provided previously by GEE" should not be proprietary. Furthermore, feed to Selexol is given in Case 2, but not in Case 1. Why? • Detailed description should refer to the stream number in the process flow diagram so that the readers can understand each stream. For an example, stream 15 in Exhibit 3-17 is not mentioned anywhere in the report. • The plant cost is presented nicely by unit process blocks. There should also be a detailed water balance, steam balance, and utility summary by each unit process block.	Not feasible to change entire report structure now. Stream to Selexol in Case 2 should not have been shown. Still maintain these streams are proprietary. If gas compositions are reported on the internet and/or in reports, why is it viewed as proprietary? Please reconsider and use non-proprietary data if possible. Claus tail gas stream is mentioned for all cases on p. 42. Beyond the scope of the study.
12.7 -	For each IGCC case, there is a detailed major equipment list. If a process flow diagram showing this major equipment can be included in the report, it will provide a very good description of the process	Beyond the scope of the study.
12.8 +	**Specific Comments:** Page 5: The conclusions shown in the Executive Summary are too obvious and simple. For	Some additional analysis will be included. This information would be

No.	COMMENT	RESPONSE
	example, a more in-depth analysis would yield a conclusion indicating at what price differential, between coal and natural gas, IGCC will have a lower LCOE.	useful…as mentioned in 11.7, are there some sensitivities that should be included?
12.9 -	Exhibits for process flow diagrams, such as Exhibit 3-2.3, are not readable. The font size for equipment descriptions should be larger.	Should be legible on 11x17 paper.
12.10	Page 17, 1st paragraph: "The EIA projection of 2005 coal cost is $29.92/ton or $1.50/MM Btu." This implies that the heating value of the coal is 9,973 Btu/lb. Then, the authors used "in-house cost data to adjust the $/ton value for bituminous coal in a Midwestern location to $29.63/ton." Thus, it implies that the higher HHV coal (11,666 Btu/lb) costs less than the lower HHV coal (9,973 Btu/lb). Is it correct?	Determine if cost does go down (slightly) for higher HHV coal.
12.11 ?	Page 21, Raw Water Usage: The raw water usage was determined by adjusting the water usage from a 2005 NETL study for a different plant size (500 MW) with a different coal (Pittsburgh #8 vs. Illinois #6). Recommendation: Water balance for each case should be developed independently in this study. The water usage estimate is too important to be obtained via adjustment from a previous study. The effort for a new water balance should be small if the amount of engineering effort is available, as implied from this report.	This issue was raised previously – waiting on NETL to decide how to handle water balances. Include water balance per item #5 in guidance document
12.12 +	Page 23, 6th bullet: Define "relative equipment/material/labor factor of 1.0."	Will add description.
12.13 -	Page 24, Cost of Electricity: "factors developed based on EPRI Technical Assessment Guide methodology." The EPRI TAG is only available to EPRI-members. Recommendation: Use the NETL financial model.	Not feasible at this point in the study. This may be feasible now….and perhaps preferred. Again, discuss status with John Wimer.
12.14 -	Page 33, 1st paragraph: Case 1 is supposed to be a "radiant-only" configuration. In the 2nd paragraph, the plant configuration utilizes an RSC followed by a water-filled quench chamber. Recommendation: Better define "radiant-only" and "radiant-convective" configuration.	The radiant only definition was provided in several places. GE's labeling for the gas cooler is confusing,

No.	COMMENT	RESPONSE
		so it would be worth one paragraph that compares and contrasts the various configuration and identifies which is used in this study.
12.15 ?	Page 263: The "shift unit" is missing in the table. Is it mislabeled as "5A.4 COS Hydrolysis"?	Response in progress.
12.16 +	Page 357, Exhibit 4-27 under "Process Wastewater": Why is "gasification activity" mentioned here?	Will make necessary change.

No.	COMMENT	RESPONSE
12.17 ?	Case 1 and 2 ASU oxygen compressor power: Why is the power consumption for a larger oxygen stream less than that for a smaller stream? They are not too far off. But, they are wrong directionally. They might not come from the same source.	Same as 8.25. Response in progress.

Oxygen Compressor Power Comparison

	Case 1	Case 2
ASU plant capacity, TPD	5,000 (p 78)	5,200 (p 109)
Air feed to ASU, #/hr		
Stream 1	1,517 K	1,878K
Stream 21 (from GT)	286K	No air extraction
Subtotal air feed	1,803K	1,878K
Oxygen out, #/hr		
Stream 5 (to gasifier)	407,816	422,943
Stream 3	6,150	7,065
Subtotal oxygen	413,966	430,008
Oxygen compressor, KW	11,520 (p 65)	11,080 (p 96)
ASU aux. KW	1,000	1,000

No.	COMMENT	RESPONSE
12.18 ?	CO_2 compressor power: In the table below, comparing the compressor power between Case 4 (E-Gas) and Case 6 (Shell), Shell's CO_2 compressor power is 9 percent higher while its flow rate is only 4.7 percent higher than those in Case 4. Why? Comparison between Case 2 and other cases will take more work because Case 2 has a different compressor inlet pressure.	Response in progress. Many of these discrepancies have been noted by this reviewer and others. Costing group should review all costs and confirm reasonableness before report is submitted as a final.

CO_2 Compressor Power

	Case 2	Case 4	Case 6
CO_2 product flow rate, #/hr	1,093.7K (19)	989K (16)	1,035.9K (19)
Temp. ºF	155	156	155
Pressure, psia	2214	2214	2200
	P 95	P 164	P 228
Feed to Selexol, lb/hr	1,259K (14)	1,190 (11)	1,267 (16)
Pressure, psia	728	496	504
Note – this gives some indication on the CO_2 compressor inlet pressure			
CO_2 compressor, KW	28,910 (P 96)	26,470 (P 165)	28,880 (P 229)

<table>
<tr><th>No.</th><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td>12.19
?</td><td>Extraction air for ASU: As shown in table below, the amount of air extracted from the GT is a nominal 5 percent (4 to 6 percent). Please explain the variance and the selection of 5 percent in the process description section. The maximum percentage of air extraction as reported in the literature is 20 percent.

Extraction Air for ASU
<table>
<tr><th></th><th>Case 1</th><th>Case 3</th><th>Case 5</th></tr>
<tr><td>CO_2 product flow rate, #/hr</td><td>286,060 (21)</td><td>989K (16)</td><td>428,146 (22)</td></tr>
<tr><td>Temp. F</td><td>155</td><td>156</td><td>155</td></tr>
<tr><td>Pressure, psia</td><td>4.0%</td><td>4.2%</td><td>6.0%</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td>Feed to Selexol, lb/hr</td><td>15.9%</td><td>18.9%</td><td>27.7%</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
</table></td><td>Response in progress. This is the type of info that needs to be referenced and justified.</td></tr>
<tr><td>12.20
?</td><td>Case 1 PFD (Exhibit 3-17, P. 62): This is the only PFD showing: (a) a return stream (15) from the Claus unit to the Selexol unit, and (b) an unmarked stream from the Selexol unit to a compressor. Case 2 (Exhibit 3-32), Case 3 (Exhibit 3-51), and Case 4 (Exhibit 3-62) do not have the similar stream. Please explain.</td><td>Response in progress.</td></tr>
<tr><td>12.21
-</td><td>Where are Cases 7 and 8?</td><td>Explained in introduction.</td></tr>
<tr><td>12.22
+</td><td>Table of Contents: Some section headings are not bolded. Consistency is needed.</td><td>See comment 4.29</td></tr>
</table>

No.	COMMENT	RESPONSE
13. Comments – Set 13 [DS]		
13.1 -	The report is well written and will provide a valuable contribution to our understanding and expectations for advanced and conventional fossil fuel power plants. In general, the report format is easy to follow but it would be useful to consider excluding reference to Cases 7 and 8, as those are not analyzed in this study, but will be done in a subsequent planned study. Some more specific comments follow.	Necessary to explain Cases 7 and 8 or else discontinuity in numbering would be questioned.
13.2 +	Environmental presumptive emission limits (Exhibit 2-5): Provide a better discussion of selecting environmental performance targets. See, for instance, http://www.epa.gov/ttn/catc/rblc/htm/welcome.html. If possible, refer to recent permit applications or other information from the EPA RBLC clearinghouse. There is not a one-size-fits-all for BACT selection. The performance targets in general appear reasonable except for IGCC SO_2 control that appears to be overly aggressive.	Will consider additional backup material for BACT selections.
13.3 +	Reference is made to Exhibit 2-6 rather abruptly; it would be worthwhile to include some background discussion of the Best Demonstrated Technology approach that is used to develop the NSPS. Also, NSPS requirements for gas turbines have recently been published and should be included to complete the existing NSPS requirements for systems used in this study (see http://www.epa.gov/ttn/atw/combust/turbine/turbnsps.html).	Will modify text accordingly.
13.4 -	Executive Summary, Exhibit ES-7: It would be useful to include power generation (MWh or kWh) at design capacity factor. This would help the reader put into context the various electricity production rates that derive from the design basis for the study – that is, two F-Class turbines for IGCC and a constant 550 MWe net output capacity for the PC cases.	Others have complained already too much information in this Exhibit, this is a simple calc the reader can perform.
13.5 ?	The F class turbine is used for designs that include CO_2 capture. A brief discussion of the difference between firing syngas and hydrogen-rich fuel is warranted, since the reader assumes that this system (with hydrogen rich fuel) is available for deployment. Has the design of the turbine included consideration of nitrogen dilution that would mitigate concerns for burning a hydrogen rich fuel? Are there known issues with NOx formation from combustion of a hydrogen-rich stream that should be discussed?	Response pending. Report should include this discussion and explanation for how the turbine was modeled / assumptions for performance on H2 fuel.

No.	COMMENT	RESPONSE
13.6 ?	A set of calculations derived from the report has been incorporated into tables (*See Attachments 2 through 5*) and the following comments are noted: • SO_2 removal efficiency is >99.8 percent for IGCC cases. What is the reason for driving sulfur levels to such a low point? The level of sulfur capture is well beyond NSPS limits. Consider revising to about 99.5 percent removal, since this can be tolerated in the turbine without adverse performance effects as indicated later in the study. • Case 3 appears to have an incorrect SO_2 emission rate in the executive summary. Please revise.	Response in progress.
13.7 -	The stream table for Case 2 includes enthalpy information, whereas this is not included for any other cases – but, it should be added.	Enthalpy information is provided in separate tables.

Attachment 1: Comparison of IGCC Plant Costs with and without CO_2 Capture

Comparison of IGCC Plant Costs									
Acct Num	Description	Equip. Cost	Material Cost	Labor		Erected Cost	Project Contingencies	Tot. Plant Cost	
				Direct	Indirect			$x1000	$/kW
1	COAL HANDLING SYSTEM								
1.1	Coal Receive & Unload	1.2%	0%	1.2%	1.0%	1.2%	1.2%	1.2%	1.4%
1.2	Coal Stackout & Reclaim	1.2%	0%	1.2%	1.5%	1.2%	1.2%	1.2%	1.4%
1.3	Coal Conveyors & Yard Crush	1.2%	0%	1.2%	1.5%	1.2%	1.2%	1.2%	1.4%
1.4	Other Coal Handling	1.2%	0%	1.4%	0%	1.2%	1.2%	1.2%	1.4%
1.5	Sorbent Receive & Unload	*no change*							
1.6	Sorbent Stackout & Reclaim	*no change*							
1.7	Sorbent Conveyors	*no change*							
1.8	Other Sorbent Handling	*no change*							
1.9	Coal & Sorbent Handling Foundations	0%	1.2%	1.2%	1.1%	1.2%	1.2%	1.2%	1.4%
	Sub Total 1	**1.2%**	**1.2%**	**1.2%**	**1.1%**	**1.2%**	**1.2%**	**1.2%**	**1.4%**
2	COAL PREP& FEED SYSTEMS								
2.1	Coal Crushing & Drying	*included in 2.3*[1]							
2.2	Prepared Coal Storage & Feed	1.6%	1.8%	1.5%	0%	1.6%	1.9%	1.7%	1.9%
2.3	Slurry Prep & Feed	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.8%
2.4	Misc. Coal Prep & Feed	1.6%	1.5%	1.6%	1.9%	1.6%	1.6%	1.6%	1.8%
2.5	Sorbent Prep Equipment	*no change*							
2.6	Sorbent Storage & Feed	*no change*							
2.7	Sorbent Injection System	*no change*							
2.8	Booster Air Supply System	*no change*							
2.9	Coal & Sorbent Feed Foundation	0%	4.0%	1.6%	1.9%	2.9%	2.9%	2.9%	3.3%
	Sub Total 2	**1.6%**	**2.3%**	**1.6%**	**1.7%**	**1.8%**	**1.9%**	**1.8%**	**2.0%**

Comparison of IGCC Plant Costs									
Acct Num	Description	Equip. Cost	Material Cost	Labor Direct	Labor Indirect	Erected Cost	Project Contingencies	Tot. Plant Cost $x1000	Tot. Plant Cost $/kW
3	FEEDWATER & MISC. BOP SYSTEMS								
3.1	Feedwater System	-5.3%	-5.3%	-5.3%	-5.2%	-5.3%	-5.3%	-5.3%	-6.0%
3.2	Water Makeup & Pretreating	-6.1%	-6.3%	-6.0%	-4.5%	-6.0%	-6.0%	-6.0%	-6.9%
3.3	Other Feedwater Subsystems	-5.3%	-5.2%	-5.3%	-6.3%	-5.3%	-5.2%	-5.3%	-6.0%
3.4	Service Water Systems	-6.2%	-6.1%	-6.1%	-6.1%	-6.1%	-6.0%	-6.1%	-7.0%
3.5	Other Boiler Plant Systems	-6.1%	-6.2%	[1]-6.1%	-5.9%	-6.1%	-6.1%	-6.1%	-7.0%
3.6	FO Supply Sys & Nat Gas	-1.5%	-1.4%	-1.4%	0%	-1.4%	-1.4%	-1.4%	-1.6%
3.7	Waste Treatment Equipment	-6.1%	0%	-6.2%	-5.9%	-6.1%	-6.1%	-6.1%	-7.0%
3.8	Misc Power Plant Equipment	-1.5%	-1.6%	-1.4%	0%	-1.4%	-1.4%	-1.4%	-1.6%
	Sub Total 3	**-5.1%**	**-5.1%**	**-5.3%**	**-5.1%**	**-5.2%**	**-5.1%**	**-5.2%**	**-5.9%**
4	GASIFIER & ACCESSORIES								
4.1	Syngas Cooler Gasifier System	*no change*							
4.2	Syngas Cooler (w/Gasifier - $)	*no change*[2]							
4.3a	ASU/Oxidant Compression	*no change*[3]							
4.4	Scrubber & Low Temp. Cooling	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	7.0%
4.5	Black Water & Sour Gas Section	6.3%	6.3%	6.3%	6.2%	6.3%	6.3%	6.3%	7.2%
4.6	Other Gasification Equip	6.3%	6.3%	6.3%	6.2%	6.3%	6.3%	6.3%	7.2%
4.8	Major Component Rigging	*no change*[4]							
4.9	Gasification Foundations	0%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%	-0.6%
	Sub Total 4	**0.6%**	**1.6%**	**1.4%**	**1.4%**	**1.0%**	**1.1%**	**1.0%**	**1.1%**

Comparison of IGCC Plant Costs									
Acct Num	Description	Equip. Cost	Material Cost	Labor Direct	Labor Indirect	Erected Cost	Project Contingencies	Tot. Plant Cost $x1000	Tot. Plant Cost $/kW
5A	GAS CLEANUP & PIPING								
5A.1	Single Stage Solexol	94.8%	0%	94.8%	94.8%	94.8%	94.8%	94.8%	108.2%
5A.2	Elemental Sulfur Plant	1.8%	1.8%	1.8%	1.9%	1.8%	1.8%	1.8%	2.1%
5A.3	Mercury Removal	35.1%	0%	35.3%	35.7%	35.2%	35.6%	35.3%	40.3%
5A.4	COS Hydrolysis or WGS[5]	177.8%	0%	-7.8%	-7.4%	72.9%	72.9%	72.9%	83.2%
5A.5	Pressure Swing Absorption Sys.	*no change*							
5A.6	Blowback Gas Systems	*no change*							
5A.7	Fuel Gas Piping	0%	-2.6%	-2.6%	-2.7%	-2.6%	-2.6%	-2.6%	-3.0%
5A.8	HGCU Foundations	0%	4.7%	4.6%	4.9%	4.7%	4.6%	4.7%	5.3%
	Sub Total 5A	**75.3%**	**0.8%**	**51.7%**	**51.8%**	**59.7%**	**45.3%**	**57.9%**	**66.1%**
5B	CO_2 REMOVAL & COMPRESSION:	*only applicable to CO_2 capture case*							
6	COMBUSTION TURBINE/ACCESSORIES								
6.1	Combustion Turbine Generator	5.0%	0%	5.0%	5.1%	5.0%	5.0%	5.0%	5.7%
6.2	Combustion Turbine Accessories	*no change*[6]							
6.3	Compressed Air Piping	*no change*							
6.9	Combustion Turbine Foundations	*no change*							
	Sub Total 6	**5.0%**	**0%**	**4.4%**	**4.4%**	**4.9%**	**4.9%**	**4.9%**	**5.6%**
7	HRSG, DUCTING & STACK								
7.1	Heat Recovery Steam Generator	*no change*							
7.2	SCR System	*no change*							
7.3	Ductwork	0%	4.6%	4.5%	4.7%	4.5%	4.6%	4.5%	5.2%
7.4	Stack	4.6%	0%	4.5%	5.9%	4.6%	4.5%	4.6%	5.2%
7.9	HRSG, Duct & Stack Foundations	0%	4.5%	4.6%	5.7%	4.6%	4.6%	4.6%	5.2%
	Sub Total 7	**0.4%**	**4.5%**	**2.0%**	**2.3%**	**1.0%**	**1.4%**	**1.0%**	**1.1%**

Comparison of IGCC Plant Costs									
Acct Num	Description	Equip. Cost	Material Cost	Labor Direct	Labor Indirect	Erected Cost	Project Contingencies	Tot. Plant Cost $x1000	Tot. Plant Cost $/kW
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	-7.7%	0%	-7.6%	-7.8%	-7.7%	-7.7%	-7.7%	-8.8%
8.2	Turbine Plant Auxiliaries	-7.1%	0%	-7.2%	-7.4%	-7.2%	-7.6%	-7.2%	-8.3%
8.3	Condenser & Auxiliaries	-11.7%	0%	-11.7%	-12.0%	-11.7%	-11.7%	-11.7%	-13.3%
8.4	Steam Piping	-7.2%	0%	-7.2%	-7.5%	-7.2%	-7.2%	-7.2%	-8.2%
8.9	TG Foundations	0%	-7.2%	-7.2%	-8.0%	-7.2%	-7.1%	-7.2%	-8.2%
	Sub Total 8	**-8.1%**	**-7.2%**	**-7.9%**	**-8.2%**	**-8.1%**	**-7.9%**	**-8.0%**	**-9.2%**
9	COOLING WATER SYSTEM								
9.1	Cooling Towers	-5.4%	0%	-11.4%	-12.0%	-6.5%	-6.4%	-6.5%	-7.4%
9.2	Circulating Water Pumps	-11.4%	0%	-10.8%	-16.7%	-11.4%	-11.5%	-11.4%	-13.0%
9.3	Circ. Water System Auxiliaries	-12.2%	0%	-13.3%	0%	-12.2%	-7.1%	-11.8%	-13.4%
9.4	Circ. Water Piping	0%	-11.5%	-11.4%	-11.1%	-11.4%	-11.4%	-11.4%	-13.1%
9.5	Make-up Water System	-11.5%	0%	-11.5%	-11.5%	-11.5%	-11.5%	-11.5%	-13.1%
9.6	Component Cooling Water Sys	-8.3%	-8.4%	-8.4%	-9.4%	-8.4%	-8.5%	-8.4%	-9.6%
9.9	Circ. Water System Foundations	0%	-11.5%	-11.5%	-11.7%	-11.5%	-11.4%	-11.5%	-13.1%
	Sub Total 9	**-7.7%**	**-11.2%**	**-11.3%**	**-11.5%**	**-9.9%**	**-10.4%**	**-9.9%**	**-11.4%**
10	ASH/SPENT SORBENT HANDLING								
10.1	Slag Dewatering & Cooling	-4.5%	-4.5%	-4.5%	-4.5%	-4.5%	-4.5%	-4.5%	-5.2%
10.2	Gasifier Ash Depressurization	*no change*							
10.3	Cleanup Ash Depress.	*no change*							
10.4	High Temp. Ash Piping	*no change*							
10.5	Other Ash Recovery Equip.	*no change*							
10.6	Ash Storage Silos	0.6%	0%	0.6%	0%	0.6%	0.6%	0.6%	0.7%
10.7	Ash Transport & Feed Equip.	0.6%	0%	0.7%	0%	0.6%	0.7%	0.6%	0.7%
10.8	Misc. Ash Handling Equip.	0.6%	0.6%	0.6%	0%	0.6%	0.7%	0.6%	0.7%
10.9	Ash/Spent Sorbent Foundations	*no change*							
	Sub Total 10	**-3.6%**	**-3.6%**	**-4.1%**	**-4.0%**	**-3.8%**	**-3.5%**	**-3.8%**	**-4.3%**

Comparison of IGCC Plant Costs									
Acct Num	Description	Equip. Cost	Material Cost	Labor Direct	Labor Indirect	Erected Cost	Project Contingencies	Tot. Plant Cost $x1000	Tot. Plant Cost $/kW
11	ACCESSORY ELECTRIC PLANT								
11.1	Generator Equipment	-2.1%	0%	-2.2%	-3.7%	-2.2%	-2.2%	-2.2%	-2.5%
11.2	Station Service Equipment	18.4%	0%	18.5%	15.8%	18.4%	18.5%	18.4%	21.0%
11.3	Switchgear & Motor Control	18.4%	0%	18.4%	18.3%	18.4%	18.3%	18.4%	21.0%
11.4	Conduit & Cable Tray	0%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	21.0%
11.5	Wire & Cable	0%	18.4%	18.4%	18.5%	18.4%	18.4%	18.4%	21.0%
11.6	Protective Equipment	0%	-2.5%	-2.4%	-2.1%	-2.4%	-2.4%	-2.4%	-2.8%
11.7	Standby Equipment	-2.0%	0%	-1.6%	0%	-1.8%	-1.5%	-1.7%	-2.0%
11.8	Main Power Transformers	-2.4%	0%	-2.5%	0%	-2.4%	-2.5%	-2.4%	-2.8%
11.9	Electrical Foundations	0%	-2.3%	-2.4%	-4.2%	-2.5%	-2.5%	-2.5%	-2.8%
	Sub Total 11	**10.6%**	**16.1%**	**14.1%**	**14.0%**	**13.1%**	**13.7%**	**13.2%**	**15.0%**
12	INSTRUMENTATION & CONTROL								
12.1	IGCC Control Equipment	*no change*							
12.2	Combustion Turbine Control	*no change*							
12.3	Steam Turbine Control	*no change*							
12.4	Other Major Component Control	-4.1%	0%	-4.1%	-3.4%	-4.1%	-3.8%	-4.0%	-4.6%
12.5	Signal Processing Equipment	*no change*[6]							
12.6	Control Boards, Panels, & Racks	-4.1%	0%	-4.2%	0%	-4.0%	-4.2%	-4.0%	-4.6%
12.7	Computer & Accessories	-4.1%	0%	-4.2%	-14.3%	-4.1%	-4.2%	-4.1%	-4.7%
12.8	Instrument Wiring & Tubing	0%	-4.0%	-4.1%	-4.2%	-4.1%	-4.2%	-4.1%	-4.7%
12.9	Other I&C Equipment	-4.1%	0%	-4.1%	-4.0%	-4.1%	-3.9%	-4.1%	-4.6%
	Sub Total 12	**-4.1%**	**-4.0%**	**-4.1%**	**-4.2%**	**-4.1%**	**-4.1%**	**-4.1%**	**-4.7%**
13	IMPROVEMENTS TO SITE								
13.1	Site Preparation	0%	-1.1%	-1.2%	-0.8%	-1.1%	-1.2%	-1.2%	-1.3%
13.2	Site Improvements	0%	-1.2%	-1.2%	-0.7%	-1.2%	-1.2%	-1.2%	-1.4%
13.3	Site Facilities	-1.2%	0%	-1.2%	-1.0%	-1.2%	-1.2%	-1.2%	-1.4%
	Sub Total 13	**-1.2%**	**-1.2%**	**-1.2%**	**-0.9%**	**-1.2%**	**-1.2%**	**-1.2%**	**-1.4%**

Comparison of IGCC Plant Costs									
Acct Num	Description	Equip. Cost	Material Cost	Labor Direct	Labor Indirect	Erected Cost	Project Contingencies	Tot. Plant Cost $x1000	Tot. Plant Cost $/kW
14	BUILDINGS & STRUCTURES								
14.1	Combustion Turbine Area	*no change*							
14.2	Steam Turbine Building	0%	-4.4%	-4.4%	-4.1%	-4.4%	-4.5%	-4.4%	-5.0%
14.3	Administration Building	0%	-0.8%	-1.0%	0%	-0.9%	-0.9%	-0.9%	-1.0%
14.4	Circulation Water Pumphouse	0%	-0.8%	0%	0%	-0.5%	-1.8%	-0.8%	-0.9%
14.5	Water Treatment Buildings	0%	-0.9%	-0.9%	0%	-0.8%	-0.9%	-0.9%	-1.0%
14.6	Machine Shop	0%	-0.9%	-0.9%	0%	-0.9%	-1.3%	-1.0%	-1.1%
14.7	Warehouse	0%	-0.8%	-0.8%	0%	-0.8%	-0.8%	-0.8%	-0.9%
14.8	Other Buildings & Structures	0%	-0.6%	-0.8%	0%	-0.7%	-1.2%	-0.8%	-0.9%
14.9	Waste Treating Building & Str.	0%	-0.9%	-0.8%	0%	-0.8%	-0.8%	-0.8%	-0.9%
	Sub Total 14	**0%**	**-2.0%**	**-2.3%**	**-1.8%**	**-2.2%**	**-2.3%**	**-2.2%**	**-2.5%**
	TOTAL CHANGE IN COST	**9.9%**	**0.6%**	**13.3%**	**13.3%**	**9.7%**	**9.7%**	**9.7%**	**11.0%**

[1] Equipment, material, and direct labor costs associated with line item 2.1 are included in the 2.3 line item
[2] Equipment, material, and direct labor costs associated with line item 4.2 are included in the 4.1 line item
[3] Direct labor costs associated with line item 4.3a bear the annotation "w/ equip" but equipment costs for this item do not change across the two cases
[4] Equipment and direct labor costs associated with line item 4.8 are included in the 4.1 and 4.2 line items
[5] Although line item 5A.4 is entitled "COS Hydrolysis" in both Cases, it is assumed that this is the WGS cost in the CO_2 capture case, as: (1) no cost is listed for the WGS process and, (2) a COS Hydrolysis system is not necessary when a WGS process is present
[6] Equipment and direct labor costs associated with line item 6.2 are included in the 6.1 line item

Attachment 2: Integrated Gasification Combined Cycle Calculations

	Integrated Gasification Combined Cycle					
	GEE R+Q		CoP E-Gas FSQ		Shell	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CO_2 Capture	No	Yes	No	Yes	No	Yes
Gross Power Output (kWe)	768,890	741,110	734,040	680,170	735,610	666,800
Auxiliary Power Requirement (kWe)	125,370	177,750	122,070	165,440	115,380	166,260
Net Power Output (kWe)	643,520	563,360	611,970	514,730	620,230	500,540
Coal Flowrate (lb/hr)	487,200	505,272	465,295	480,704	450,100	478,652
Natural Gas Flowrate (lb/hr)	0	0	0	0	0	0
HHV Thermal Input (kWth)	1,665,722	1,727,509	1,590,829	1,643,512	1,538,878	1,636,496
Net Plant HHV Efficiency (%)	0.386	0.326	0.385	0.313	0.403	0.306
Net Plant HHV Heat Rate (Btu/kW-hr)	8,832	10,463	8,870	10,895	8,466	11,156
Total Plant Cost ($x1000)	1,001,730	1,098,582	867,422	957,994	988,041	1,127,383
Total Plant Cost ($/kW)	1,557	1,950	1,417	1,861	1,593	2,252
Total Capital Requirement ($/kW)	1,730	2,166	1,576	2,068	1,770	2,500
LCOE (mills/kWh) @85% CF	54.7	67.6	49.4	63.6	53.8	74
LCOE (mills/kWh) @80% CF	56.9	70.5	51.5	66.3	56.1	77.2
LCOE (mills/kWh) @ 65% CF	65.9	81.7	59.5	76.9	65.1	89.9
CO_2 Emissions (lb/hr)	1,118,252	66,296	1,081,737	128,737	1,046,163	76,320
CO_2 Emissions (tons/year) @ 85% CF	4,163,252	246,820	4,027,307	479,288	3,894,865	284,139
CO_2 Emissions (tonnes/year) @ 85% CF	3,776,902	223,915	3,653,573	434,810	3,533,421	257,771
CO_2 Emissions (lb/MMBtu)	196.7	11.2	199.3	23	199.2	13.7
CO_2 Emissions (kg/MWh)	788.2	53.4	801.8	113.4	765.1	69.2
CO_2 Emissions (lb/MWh)	1737.71	117.68	1767.63	250.11	1686.73	152.48
Cost of CO_2 Avoided ($/tonne)	0	17.7	0	20.6	0	29
Cost of CO_2 Avoided ($/ton)	0	19.5	0	22.7	0	32
SO_2 Emissions (tons/y) at 85% CF	211	173	66	158	122	159

	Integrated Gasification Combined Cycle					
	GEE R+Q		CoP E-Gas FSQ		Shell	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
NOx Emissions (tons/y) at 85% CF	1,093	950	1,176	986	1,153	964
Particulates Emissions (tons/y) at 85% CF	127	132	121	125	117	125
Hg Emissions (tons/y) at 85% CF	0.023	0.023	0.022	0.022	0.021	0.022
CO_2 Emissions (tons/y) at 85% CF	4,160,000	247,000	4,030,000	479,000	3,890,000	284,000
SO_2 Emissions (tons/y) @ 85% CF	211	173	66	158	122	159
NOx Emissions (tons/y) @ 85% CF	1,093	950	1,176	986	1,153	964
Particulates Emissions (tons/y) @ 85% CF	127	132	121	125	117	125
Hg Emissions (tons/y) @ 85% CF	0.023	0.023	0.022	0.022	0.021	0.022
CO_2 Emissions (tons/y) @ 85% CF	4,160,000	247,000	4,030,000	479,000	3,890,000	284,000
Electricity / Thermal Energy, MWh/MMBtu	0.113	0.095	0.113	0.092	0.118	0.090
Electricity / Thermal, Energy MMBtu/MMBtu	0.386	0.325	0.385	0.314	0.403	0.307
Electricty kWe	643,526	561,141	612,175	515,829	620,275	501,833
		0.13		0.16		0.19
Thermal Input, MMBtu/y	42,331,323	43,901,528	40,428,052	41,766,896	39,107,811	41,588,597
Power Generation, MWh @85% CF	4,791,692	4,178,256	4,558,256	3,840,864	4,618,567	3,736,646
NOx lb/MMBtu	0.052	0.043	0.058	0.047	0.059	0.046
NOx lb/MWh	0.456	0.455	0.516	0.513	0.499	0.516
SO_2 lb/MMBtu	0.0100	0.0079	0.0033	0.0076	0.0062	0.0076
SO_2 lb/MWh	0.088	0.083	0.029	0.082	0.053	0.085
SO_2 Removal Efficiency	0.998	0.998	0.999	0.998	0.999	0.998

Attachment 3: Pulverized Coal Boiler Calculations

	Pulverized Coal Boiler			
	PC Subcritical		PC Supercritical	
	Case 9	Case 10	Case 11	Case 12
CO_2 Capture	No	Yes	No	Yes
Gross Power Output (kWe)	596,610	690,170	593,470	672,370
Auxiliary Power Requirement (kWe)	46,630	140,502	43,240	122,430
Net Power Output (kWe)	549,980	549,668	550,230	549,940
Coal Flowrate (lb/hr)	442,620	672,637	417,731	596,881
Natural Gas Flowrate (lb/hr)	0	0	0	0
HHV Thermal Input (kWth)	1,513,304	2,299,725	1,428,210	2,040,717
Net Plant HHV Efficiency (%)	0.363	0.239	0.385	0.269
Net Plant HHV Heat Rate (Btu/kW-hr)	9,389	14,276	8,857	12,662
Total Plant Cost ($x1000)	727,707	1,296,190	745,688	1,302,370
Total Plant Cost ($/kW)	1,323	2,358	1,355	2,368
Total Capital Requirement ($/kW)	1,474	2,626	1,508	2,635
LCOE (mills/kWh) @85% CF	49.9	86.3	49.7	83.5
LCOE (mills/kWh) @80% CF	51.8	89.6	51.6	86.8
LCOE (mills/kWh) @ 65% CF	59.2	102.6	59.3	99.9
CO_2 Emissions (lb/hr)	1,050,872	159,709	991,777	141,712
CO_2 Emissions (tons/year) @ 85% CF	3,912,395	594,595	3,692,386	527,595
CO_2 Emissions (tonnes/year) @ 85% CF	3,549,325	539,417	3,349,732	478,634
CO_2 Emissions (lb/MMBtu)	203.5	20.4	203.5	20.4
CO_2 Emissions (kg/MWh)	866.7	131.8	817.6	116.9
CO_2 Emissions (lb/MWh)	1910.75	290.55	1802.48	257.69
Cost of CO_2 Avoided ($/tonne)	0	49.5	0	48.2
Cost of CO_2 Avoided ($/ton)	0	54.5	0	53.1
SO_2 Emissions (tons/y) at 85% CF	1,649	0	1,556	0
NOx Emissions (tons/y) at 85% CF	1,346	2,045	1,270	1,815

	Pulverized Coal Boiler			
	PC Subcritical		PC Supercritical	
	Case 9	Case 10	Case 11	Case 12
Particulates Emissions (tons/y) at 85% CF	250	380	236	337
Hg Emissions (tons/y) at 85% CF	0.041	0.062	0.039	0.055
CO_2 Emissions (tons/y) at 85% CF	3,910,000	595,000	3,690,000	528,000
SO_2 Emissions (tons/y) @ 85% CF	1,649		1,556	
NOx Emissions (tons/y) @ 85% CF	1,346	2,045	1,270	1,815
Particulates Emissions (tons/y) @ 85% CF	250	380	236	337
Hg Emissions (tons/y) @ 85% CF	0.041	0.062	0.039	0.055
CO_2 Emissions (tons/y) @ 85% CF	3,910,000	595,000	3,690,000	528,000
Electricity / Thermal Energy, MWh/MMBtu	0.107	0.070	0.113	0.079
Electricity / Thermal, Energy MMBtu/MMBtu	0.363	0.240	0.385	0.270
Electricty kWe	550,076	551,089	550,329	551,381
		0.00		0.00
Thermal Input, MMBtu/y	38,457,894	58,443,367	36,295,384	51,861,145
Power Generation, MWh @85% CF	4,095,869	4,103,406	4,097,749	4,105,582
NOx lb/MMBtu	0.070	0.070	0.070	0.070
NOx lb/MWh	0.657	0.997	0.620	0.884
SO_2 lb/MMBtu	0.0858	0.0000	0.0857	0.0000
SO_2 lb/MWh	0.805	0.000	0.759	0.000
SO_2 Removal Efficiency	0.980		0.980	

Attachment 4: Natural Gas Combine Cycle Calculations

	Natural Gas Combine Cycle	
	Advanced F Class	
	Case 13	Case 14
CO_2 Capture	No	Yes
Gross Power Output (kWe)	572,910	522,500
Auxiliary Power Requirement (kWe)	14,100	43,340
Net Power Output (kWe)	558,810	479,160
Coal Flowrate (lb/hr)	0	0
Natural Gas Flowrate (lb/hr)	165,183	165,183
HHV Thermal Input (kWth)	1,103,367	1,103,367
Net Plant HHV Efficiency (%)	0.506	0.434
Net Plant HHV Heat Rate (Btu/kW-hr)	6,737	7,857
Total Plant Cost ($x1000)	283,109	423,357
Total Plant Cost ($/kW)	507	884
Total Capital Requirement ($/kW)	568	988
LCOE (mills/kWh) @85% CF	63.9	83.7
LCOE (mills/kWh) @80% CF	64.7	84.9
LCOE (mills/kWh) @ 65% CF	67.5	89.9
CO_2 Emissions (lb/hr)	446,339	44,634
CO_2 Emissions (tons/year) @ 85% CF	1,661,720	166,172
CO_2 Emissions (tonnes/year) @ 85% CF	1,507,512	150,752
CO_2 Emissions (lb/MMBtu)	118.55	11.86
CO_2 Emissions (kg/MWh)	362.3	42.25
CO_2 Emissions (lb/MWh)	798.73	93.15
Cost of CO_2 Avoided ($/tonne)	0	61.6
Cost of CO_2 Avoided ($/ton)	0	67.9
SO_2 Emissions (tons/y) at 85% CF	0	0
NOx Emissions (tons/y) at 85% CF	127	110

	Natural Gas Combine Cycle	
	Advanced F Class	
	Case 13	Case 14
Particulates Emissions (tons/y) at 85% CF	0	0
Hg Emissions (tons/y) at 85% CF	0	0
CO_2 Emissions (tons/y) at 85% CF	1,660,000	166,000
SO_2 Emissions (tons/y) @ 85% CF		
NOx Emissions (tons/y) @ 85% CF	127	110
Particulates Emissions (tons/y) @ 85% CF		
Hg Emissions (tons/y) @ 85% CF		
CO_2 Emissions (tons/y) @ 85% CF	1,660,000	166,000
Electricity / Thermal Energy, MWh/MMBtu	0.148	0.127
Electricity / Thermal, Energy MMBtu/MMBtu	0.507	0.435
Electricty kWe	558,931	479,466
Thermal Input, MMBtu/y	28,040,084	28,040,084
Power Generation, MWh @85% CF	4,161,797	3,570,106
NOx lb/MMBtu	0.009	0.008
NOx lb/MWh	0.061	0.062
SO_2 lb/MMBtu	0.0000	0.0000
SO_2 lb/MWh	0.000	0.000
SO_2 Removal Efficiency		

Attachment 5: Emissions Calculations

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
SO_2 Emissions (tons/y) @ 85% CF	211	173	66	158	122	159
NOx Emissions (tons/y) @ 85% CF	1,093	950	1,176	986	1,153	964
Particulates Emissions (tons/y) @ 85% CF	127	132	121	125	117	125
Hg Emissions (tons/y) @ 85% CF	0.023	0.023	0.022	0.022	0.021	0.022
CO_2 Emissions (tons/y) @ 85% CF	4,160,000	247,000	4,030,000	479,000	3,890,000	284,000
	Case 9	**Case 10**	**Case 11**	**Case 12**	**Case 13**	**Case 14**
SO_2 Emissions (tons/y) @ 85% CF	1,649		1,556			
NOx Emissions (tons/y) @ 85% CF	1,346	2,045	1,270	1,815	127	110
Particulates Emissions (tons/y) @ 85% CF	250	380	236	337		
Hg Emissions (tons/y) @ 85% CF	0.041	0.062	0.039	0.055		
CO_2 Emissions (tons/y) @ 85% CF	3,910,000	595,000	3,690,000	528,000	1,660,000	166,000

2006 Cost and Performance Comparison of Fossil Energy Power Plants
ALSTOM's comments to the DOE on this draft report

Summary of Comments

The following section summarizes a number of areas where ALSTOM feels that the DOE report is deficient or misleading. Additional discussion on these points is then provided in the rest of this report.

- This report does not compare IGCC and PC technology on a consistent basis. IGCC is given the benefit of many technology improvements and optimistic performance assumptions. On the other hand, the report assumes that PC technology is static and uses overly conservative performance values.
- We agree with the first half of the statement – it was a study assumption that these technologies would be commercial to support a 2010 start-up. The reality is that some will not be commercial by then. We may need to rethink some assumptions, e.g., add a spare gasifier to achieve 85% capacity factor, include process contingencies for advanced F-class turbines, two-stage Selexol and Econamine, etc. However, we disagree with the second half of the statement – steam conditions used are more aggressive than any of the supercritical PC's currently under construction, and 98% SO2 removal is aggressive (too aggressive according to other peer reviewers).
- Decision was made to add spare gasifier when CF is 85%. RDS should include evidence that steam conditions are aggressive.

- The thermal efficiencies used in this study for SC PC appear to be 1-2% points too low for the design steam conditions. The steam conditions used are also too conservative based upon recent requests for commercial PC plants with more advanced steam conditions and with similar fuels. The combined effect is that the thermal efficiency for a advanced SC PC plant is too low by 2-3% points.
- Based on what is currently being built, steam conditions are actually aggressive. Perhaps Alstom is being asked to quote more aggressive conditions, but that information is not available to us and that's not what is currently being built.
- Include reference to conditions of PC plants currently being built.

- The capacity factor used in this study requires an availability that can be easily achieved and has been demonstrated by commercial PC plants. However, operating IGCCs have never demonstrated availabilities even close to this target without requiring backup firing of natural gas or with additional capital and O&M investment. Nevertheless, this study assumes that a new IGCC could attain this never achieved availability level without the necessity of either a spare gasifier train nor backup fuel. This is an unrealistic assumption and severely distorts the cost relationship between IGCC and PC. Adding a spare

gasifier can easily add an additional 150 $/kw to the cost of the IGCC. Even the IGCC vendors are providing spare gasifiers in their current plant offerings.

- This is a valid point. The 85% CF without a spare gasifier was a study assumption. Perhaps we need to rethink that assumption. However, adding a spare gasifier will no doubt draw criticism from the gasifier vendors who will claim that we are basing that on "yesterday's technology."
- Need to add spare gasifier at higher capacity factors, but should still include lower capacity factor case that does not require sparing.

- The environmental performance shown for PC does not reflect the capability of current technology, as demonstrated by commercial performance – whereas the environmental performance of IGCC is projected and has not been demonstrated. A risk factor needs to be added to IGCC performance to account for this uncertainty.
- The IGCC environmental performance is based on vendor quotes. The primary issue seems to be sulfur emissions and the question is why go to 99+% sulfur removal when no SCR is being used – that level of cleaning is not required. We did it solely because it is technically feasible according to the vendors. We believe the PC-based environmental performance is reasonable given current technology.
- Since reviewer cites higher demonstrated commercial performance of sulfur removal systems for PC plants, check public information to determine if this is true. Otherwise, no change suggested. Determine if sulfur removal of 99+% in the IGCC case is proven or uncertain to assess if a process contingency is needed.

- The decision to disregard byproduct costs also produces a potential bias. PC users have found excellent markets for fly ash, bottom ash, and gypsum with only reasonably nominal downside costs for disposal since all are non-hazardous materials. Compare this with the IGCC potential. Nearly all attempts in the industry historically to market sulfur or acid have been failures and create a huge potential downside to the generator for disposal costs. Additionally, the report fails to mention that the process chosen for mercury control on the IGCC case produces a hazardous waste to be disposed (per Eastman presentations). Utilities have spent hundreds of millions of dollars to rid themselves of hazardous wastes.
- Again, this was a study assumption. If we give a credit to PC-based byproducts but not IGCC, we will be open to criticism from the gasifier vendors. We would propose maintaining the no credit, no disposal cost approach. The study does say that mercury-laden carbon is a hazardous waste in the IGCC cases and the disposal costs reflect that.
- Agree to maintain no credit approach, but if IGCC disposal costs reflect mercury-laden carbon, then it is not a "no disposal cost approach." Make sure both are handled consistently and that it is spelled out in the report. Talk with Jeff Hoffmann about wording regarding market analysis being beyond scope of this study.

- The study handles the impact of CO2 capture on plant power output completely different for PC and IGCC. The PC plant was redesigned to maintain constant power output as CO_2 capture was added, while the power output from the IGCC plant was allowed to decrease. While the rationale for this is understood, it seems like the DOE is comparing apples and oranges.
- The idea was to maintain as close to 550 MW output as possible in all cases. For PC, this could be done exactly because of the ability to custom size steam turbines. In the case of IGCC, the net output is overstated in the non-capture cases and under-stated in the capture cases, but this is due to the constraint of the gas turbine output. We believe these comparisons are still valid and reasonable.
- As stated below, the supercritical plants under construction are 515-790MW. We did quick review of all PC plants and 750 - 800 seemed to be most often the size. Consider scaling results to this size.

- A quick check on the two SC PC cases indicated that the capital costs for Case 12 may be overstated by over 150 $/kw. There was no evidence of any scaling effect as the PC plant size was scaled up.
- We will investigate the scaling factors used as equipment sizes changed.

- The PC plant capacity in this study was fixed to match the IGCC capacity, which is limited by the gas turbine outlet. This does not allow for the significant scaling benefits for SC PC plants that are available at capacities up to 1100Mw. A 1000Mw PC plant would be expected to cost about 20% less than the 500Mw plant used in this study. A more fair comparison would have contrasted this plant with a 2x500Mw IGCC plant. A multiple IGCC plant would not have the same economies of scale as the PC plant would more accurately reflect the real cost differentials between the two technologies.
- The five supercritical units currently under construction range in size from 515 to 790 MW so the size selected seems reasonable. There would also be economies of scale for the 2x500 MW IGCC plant, and it's not clear that PC would derive a significant advantage from an increased scale comparison. (see comment above)

- A comparison with a similar EPRI and IEA study showed that the DOE's thermal efficiency was considerably lower for SC PC than those studies reported for very similar steam conditions and fuel.
- Without comparing study details, it's impossible to know if this is a real difference or an artifact of the model. We believe our efficiency numbers are correct.
- Confirm efficiency estimates from our models for PC plants.

- This comparison also showed that the Econamine (advanced amine for CO_2 capture) performance and costs were considerably worse in the DOE study than in the IEA PH4/33 report. This bears looking into, especially since Fluor apparently provided design information to both studies.

- As stated, our numbers were based on information provided by Fluor. We will contact Fluor to determine if they have more recent numbers that we should consider when doing the final iteration of the report.
- Good idea.

- The DOE report only considers the Econamine solvent for CO_2 capture from the PC cases. This technology is not as advanced as many of the newer technologies under development. The report shows at 70% increase in COE for the SC PC cases using Econamine for CO_2 capture. NETL recently made a presentation at the Coal-Gen conference that showed that the COE increase with a conventional MEA was only 55%. This inconsistency shows that there is considerably uncertainly in the performance and costs of the systems and raises questions why the DOE report used a system with inferior performance.
- There are many CO2 capture technologies under development. At the study outset, Econamine was the most studied and closest to being commercially available. Any other technology would reasonably require a process contingency to account for the learning curve (perhaps Econamine should as well). An exhaustive study of alternative CO2 capture technologies was beyond the scope of this study.
- Stick with Econamine, but check on performance and costs with Fluor. Also consider whether a contingency should be included for this unit.

- The discussion of CO_2 capture is completely irrelevant for the report's stated objective of presenting current market conditions for plants starting operation in 2010. This objective limits the comparison to plants that are either in contract or in final bid stage by the end of 2006. There is currently no legislation requiring CO_2 capture nor has sequestration been adequately demonstrated. Furthermore, no commercial projects with CO_2 capture are in design nor are being considered for a 2010 startup.
- Again, it was a study assumption that these technologies would be commercially available to support a 2010 startup. The argument that the comparison shouldn't even be made seems a bit gratuitous. Consideration should be given to adding a process contingency for technologies that aren't expected to be commercially available by 2010.
- We believe that this comparison is useful to identify where research should focus. The revision should apply process contingencies for technologies that aren't expected to be commercial by 2010-2012.

- Since CO_2 capture will not be required nor take place within the report's 2010 time horizon, the discussion of CO_2 capture should not be limited to CO_2 capture processes that are available today. The impact of CO_2 capture and sequestration generation costs would be dramatic using current IGCC or PC technologies. Today's CO_2 capture technologies are not the answer – lower cost processes are critical to the future of the coal industry if CO_2 capture is required. It is likely that it will be a minimum of a decade, if not longer, before protocols are developed and proven for safe, reliable sequestration of CO_2.

Therefore, the concepts for capture and sequestration realistically need to be looked at as technologies that would be available to retrofit to operating and new units in the 2015 -2020 timeframe, and also as new technologies that would incorporate CO_2 controls when installed beyond 2015.

- Performing an exhaustive study of developing CO2 capture technologies and picking the optimum one was beyond the scope of this study. The technologies chosen represent the nearest to commercial. We see no reason to change.
- Agree

- There are a large number of CO_2 capture technologies under development for PC plants, many with financial support by the DOE. These technologies have the potential to be significantly less energy intensive and more cost effective than the post-combustion capture technology used in this study. Some of the technology options under development include chilled NH_3 scrubbing, oxyfiring, and post-combustion capture with more advanced solvents. EPRI has also been evaluating advances in both IGCC and PC and correctly states that "it is a horse-race" - there is no clear technology winner for coal power generation with CO_2 capture. We believe that a more balanced approach by the DOE will show a similar result.
- See previous response.
- Suggest no changes to configuration. Should emphasize in report that these are baseline cases, and that emerging technologies provide promise that costs and performance will be improved, but that these more advanced systems were not considered in this analysis since they are not expected to be commercially available in the timeframe of this analysis.

Comments from Phil Amick (ConocoPhillips):

You said that there was some internal push-back on showing E-Gas as a lower cost than GE and Shell. There's plenty of public support for that point, including Neville Holt's (EPRI) 2003 GTC presentation.

There are several reasons for this.

- The firetube syngas cooler is much smaller and less expensive than a radiant section. E-Gas can use a firetube boiler because our two stage design reduces the gas temperature - quenching with slurry - and drops the syngas temperature into a zone where a radiant cooler is not needed.
- The firetube syngas cooler also sits next to the gasifier, instead of above or below it. This reduces the height of the main gasifier structure and saves hundreds of tons of steel and pipe.
- The E-Gas Technology proprietary slag removal system, used instead of lock hoppers below the gasifier, also contributes to the lower structure height. Wabash is 180 feet high at the top deck of the main structure. TECO and Nuon are both over 300 feet.
- The two stage E-Gas Technology uses less oxygen than GE, hence a smaller and less expensive air separation unit.
- Even beyond the gasifier high-rise, a much more compact design (because we have been gasification plant operators for twenty years, and know what the maintenance access needs are without overdesigning for them).

I know that all sounds like a sales pitch - it is, we advertise that we are lower cost.

We should use this information in the report to justify the cost difference assuming we believe it to be true. I think this is the kind of analysis the Princeton professor was looking for.
Agree

I would argue that your study isn't apples-to-apples on the relative advancement of the technologies. The E-Gas, and presumably the Shell, configurations are current commercial products. Your GE case is showing 644 MW net - far beyond what AEP or Cinergy, the current GE products, are advertising…Additionally, showing GE as slightly more efficient than E-Gas when Wabash has a 400 point better heat rate than TECO implies some other technology difference on the GE

side. Their 7FB gives them a little efficiency advantage (it's a G machine with higher firing temperatures than the 7FA or 5000F, another inequality?) - but not enough to counter the lower efficiency single stage gasifier.

In the AEP permit application they state a nominal gross output of 764 MW and a nominal net output of 629 MW. In our study we have a gross output of 769 MW and a net output of 643 MW. I wouldn't call this far beyond what they are advertising. The small difference could be that we assume 98% carbon conversion based on fines recycle. Perhaps this is more optimistic than what GE will guarantee in real life. Also note that in the Siemens comments below they refer to the efficiencies as being on a realistic relative level.
No change suggested

Capital costs are low, for both PC and IGCC. AEP was quoted in Argus Coal Daily recently as saying their IGCC was $1900/kW compared to $1700/kW for PC (attached, first article). For a Midwest location without a spare gasifier or SCR, we are in the same ballpark as the AEP number for IGCC. Excelsior (with a spare gasifier, three fuel flexibility and a hinterland location) is higher.

The real driver for this is escalating material prices, and some expectation of a tight field construction labor market through the end of the decade. I'm attaching some curves that we assembled fro the published Chemical Engineering magazine cost indices. Look in particular at the one that calculates everything based on the reference point of the study that we did with Nexant for DOE back in 2000-2001. The 'overall' plant Bare Erected Cost is up 25%. Some individual items like structural steel and heat exchangers are up nearly 50%. Labor is pretty flat, but that's looking backwards not forward….and what doesn't really show up here is that the EPC market is swamped with business and charging much higher margins, especially for jobs where they have to take any substantial risks.

We propose to re-evaluate the escalation factors used in the current study as part of the final editing. While the indication here is that $1900/kW is about right with no spare gasifier, we believe that to achieve 85% capacity factor we should include a spare gasifier, which will increase our costs to closer to this level.
Re-evaluation of escalation factors is warranted.

Comments from Dennis Horazak (Siemens)

The net efficiency comparison shown in Exhibit ES-2 depicts at least a realistic relative level, with IGCC (GE and CoP) basically on par with supercritical PC - even though the actual efficiencies seem a bit low.

We will evaluate the models to identify anything that may reduce efficiency relative to the expectations of the reviewers. Should we switch to nitrogen dilution first followed by humidification, there could be a slight efficiency increase.

Review efficiencies overall and compare to recently published performance as a check.

The capital cost comparison in Exhibit ES-4 shows a realistic increase of approximately 2.5% between subcritical and supercritical. Interestingly, the CoP (E-Gas) IGCC is only about 4.5% more than the supercritical, which seems to be too low. The GE IGCC is about 15% higher than supercritical, which seems more reasonable. These are all for the non-CO2 capture cases. Unfortunately, the report still looks at the now-outdated amine absorber for CO2 capture for PC plants, which makes the impact much greater than the case when some of the more recent solvents are used.

There are a number of cost issues that could affect this depending on how we decide to proceed – e.g., should we add a process contingency for things like the advanced F class turbine? The Econamine process was chosen for this system study, changing now would require significant rework and it's not clear it's warranted.

See guidance document for discussion on how to address contingency. Touch base with Jared Ciferno and Sean Plasynski to determine if Econamine is still today's technology. Also need to confirm with Flour that the performance and costs quote they gave us is applicable.

A quick review of the IGCC cost for the major suppliers of coal gasification in this new cost study leads us to believe that the ConocoPhillips numbers presented are a bit low. The summary taken from the report for annual levelized O&M cost is:

General Electric, no sequestration: $42,953 operating cost + $8,662 consumables = $51,615.

General Electric, with sequestration: $48,036 operating cost + $8,527 consumables = $56,563.

ConocoPhillips, no sequestration: $32,370 operating cost + $5,659 consumables = $38,029.

ConocoPhillips, with sequestration: $35,365 operating cost + $5,621 consumables = $40,986.

Shell Global, no sequestration: $36,426 operating cost + $8,191 consumables = $44,617.

Shell Global, with sequestration: $40,459 operating cost + $6,987 consumables = $47,446.

These numbers appear to be near the level that they were prior to the work on Steelhead, when both Fluor and Siemens worked with ConocoPhillips and the cost increased due to O&M labor related to several features including the extensive work on maintenance of the ceramic tiles.

O&M costs were based on a percentage of capital in all cases. To do otherwise was beyond the scope of this study. Although reasonable to scale O&M from capital costs, it leads to results that are confusing. The reviewer questions why the O&M cost is higher or lower than another, trying to relate the trend to a specific system requirement like refractory life. Also, the reviewer indicates that O&M costs overall are not high enough due to increased costs for fixing the ceramic tiles. Is it possible to find real O&M data and use as a basis for this estimate such that trends between the gasifiers are representative?