



## **Site Specific Considerations for Carbon Dioxide Capture at Existing PC Plants**

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### **Introduction**

Many power generation companies are beginning to conduct studies to identify how they will cope with Green House Gas (GHG) emissions, if and when State and/or Federal regulations are enacted. Most pundits predict that legislation will be passed in the next year to 18 months with initial reductions required as early as 2012. There are several bills being debated in Congress now. The Lieberman-Warner Bill, with significant modifications expected in committee and floor debate, has the greatest support. This bill is based on a Cap-and-Trade program that would take effect beginning in 2012. The bill calls for an immediate reduction to 2005 emission levels with a 2% per year reduction until 2050. This type of bill will place serious constraints on generation dispatch and the need for implementation of CO<sub>2</sub> capture technologies for existing plants across the country.

Most technologies being considered for capture of CO<sub>2</sub> fall into the following categories:

- Pre-combustion Capture - IGCC
- Post Combustion Capture for PC Boilers – CO<sub>2</sub> Scrubbing
- Combustion Modification – Oxy-Combustion

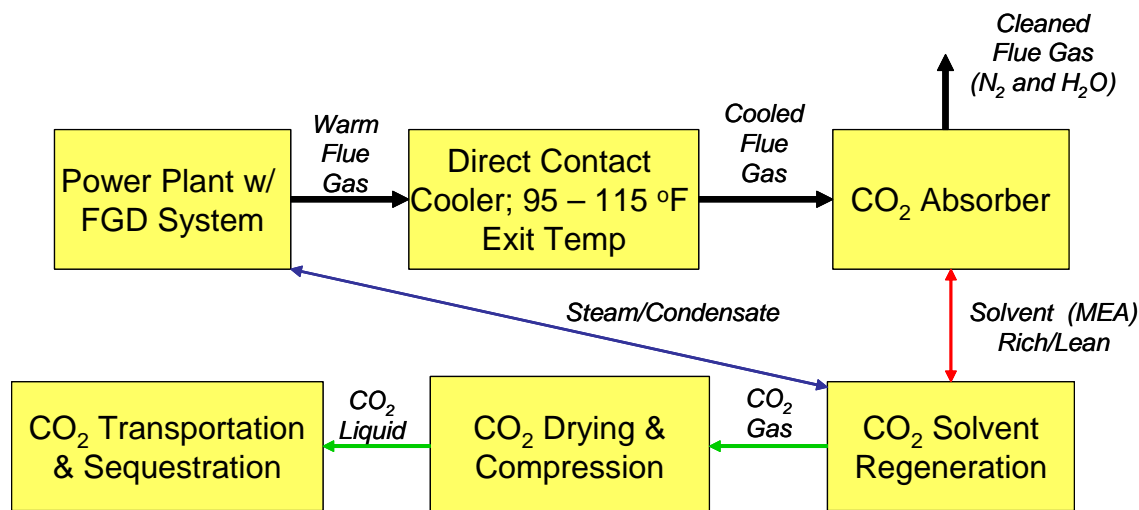
This paper focuses on post combustion capture from flue gas or CO<sub>2</sub> scrubbing technology. Amine scrubbing is only technology that has been operated commercially. In addition, an amine based CO<sub>2</sub> scrubbing process has not operated at a utility coal plant scale, which is greater than 50 MW. There are several vendors that are offering advanced technologies that are in the pilot stage of testing, but test data is still not widely available, and it is difficult to conduct preliminary studies based on these systems.

S&L prepared this paper based on work performed for a confidential client. The client was interested in understanding the cost and balance of plant (BOP) impacts of installing an amine based CO<sub>2</sub> scrubbing system on one of their base-load generating units. The client contracted with the Amine Process Technology Supplier for development of the process facility costs and with S&L for the BOP system evaluation.

This study presents some general information about amine based CO<sub>2</sub> scrubbing systems, and specific findings from the study on the impact of the amine CO<sub>2</sub> scrubbing system when integrated into an existing coal-fired power plant.

## Amine CO<sub>2</sub> Scrubbing Systems – General Information

Amine Scrubbing is a proven technology for CO<sub>2</sub> removal. The solvent is a mixture of mono-ethanol-amine (MEA) in water. The MEA is a solvent that captures CO<sub>2</sub> from the flue gas in an absorber operating at a temperature typically less than 100 °F located down stream of a typical SO<sub>2</sub> control device. The solvent is regenerated by heating the solvent to boil the CO<sub>2</sub> out of the solution. DOE has published cost estimates for this technology for application on a new PC power plant. A block diagram of the process is provided below.



Conventional (commercial) amine based CO<sub>2</sub> scrubbing is a capital and energy intensive process. There are several companies that have tested and offer advanced amine processes that have greater affinity for CO<sub>2</sub> removal and lower steam needs for regeneration. Companies working on advanced amine solvents include:

- Alstom
- Cansolv
- Dow
- Fluor
- Lummus
- MHI
- And others

There are several generic factors associated with amine scrubbing that need to be recognized:

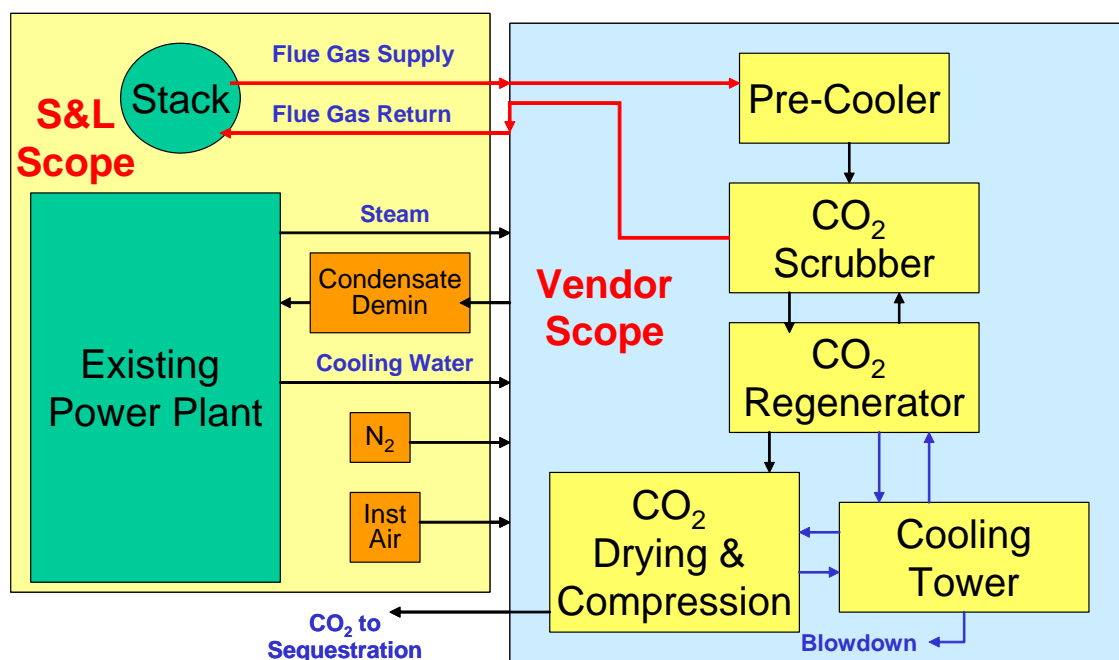
- CO<sub>2</sub> capture at levels of up to 90% appear to be feasible
- To put the energy requirements in perspective, at 90% removal the amine regeneration process requires 40 – 60 % of the total boiler steam flow at the LP/IP cross-over steam pressure to regenerate the solvent. This can result in a 15-20% loss of gross electric power output. The steam turbine design needs to be evaluated by the OEM to determine what modifications are required to divert this quantity of steam. They should also examine the capability of the bearings to withstand the operating modifications planned.

- A cooling medium is required to cool the steam generated in the stripper. This can be supplied from the existing condenser.
- Auxiliary power for the CO<sub>2</sub> removal system, new booster ID fans, and CO<sub>2</sub> compression system (for delivery to the sequestration site) is about 10 - 15% of the gross plant output.
- In total, the net total plant output is reduced by about 25 - 30% total.
- The amine solution also preferentially removes SO<sub>2</sub> and SO<sub>3</sub> from the flue gas, some of which may also be removed in the pre-scrubber. The resultant reaction of these gases with the amine form heat-stable salts that must be purged from the solution and replaced. Therefore, FGD systems upstream of the CO<sub>2</sub> system should be designed for the maximum possible removal of sulfur prior to amine treatment to reduce operating costs.
- Approximate area required for installation is about 7 acres for a 450 MW plant.

### Site Specific Study Basis – CO<sub>2</sub> Retrofit of 650 MW Unit

The objective for this study was to understand the costs and impacts of installing amine-based CO<sub>2</sub> scrubbers on one of their large, base-load coal fired units. They selected a 650 MW plant that was already equipped with selective catalytic reduction (SCR) and limestone forced oxidation (LSFO) FGD systems. The client contracted with the CO<sub>2</sub> capture technology vendor to develop a capital cost estimate and to develop a general arrangement drawing for the process located at the plant. S&L was provided with input and output requirements (power, heat, water, etc.) to interconnect with the existing plant infrastructure. S&L developed capital costs for the BOP modifications and new equipment based on the information provide by the technology supplier.

S&L developed the integration requirements of the CO<sub>2</sub> removal system with the plant. The following diagram identifies each party's scope of work.



Because of the high energy demand of the process and the burden this would put on the existing steam turbine, and the net MW plant output, the basis for the study for CO<sub>2</sub> removal was targeted to use only one-half the flue gas to achieve approximately 50% CO<sub>2</sub> removal for the plant. Under this design scenario, the study needed to consider the impact of scrubbing a higher percentage of gas (more than 50%) during part load operation of the power plant to achieve relatively higher capture rates of CO<sub>2</sub>.

Several key issues were identified that needed to be addressed in the BOP evaluation:

- The plant must deliver steam at the minimum (pressure) levels specified for the Amine System
- These conditions resulted in IP/LP crossover steam as the preferred source for solvent regeneration
- HP steam is an alternate source for solvent regeneration if LP/IP steam is not available
- IP/LP crossover steam not diverted from the LP Turbine must be sufficient for proper LP Turbine Operation
  - Turbine blade temperatures cannot get too high
  - Turbine back pressure must be sufficient for condenser
- Cooling water from the condenser inlet is a potential coolant source for the solvent regeneration system

The technology supplier provided S&L with a list of their utility requirements for steam, cooling water, instrument and service air, process water makeup, inert gas, and auxiliary power.

The impact on the steam turbine was developed using GATE CYCLE. A model of the plant system was developed. The model showed that at full load the plant could be successfully integrated and operated with the amine process to remove about one-half of the CO<sub>2</sub> produced from the unit. Additional test runs were conducted to evaluate the performance of the plant under various alternative load conditions. These results are described later.

### **Capital Costs**

Using all the inputs from the vendor and the General Arrangement Drawing developed for the site, the BOP costs were developed for the installation. Not included in these costs is the cost for the CO<sub>2</sub> pipeline or related Sequestration costs (these costs were determined for inclusion in this paper). Capital costs were developed for:

1. Duct work
2. Steam Piping
3. Cooling Water Supply & Return
4. Condensate polishing
5. Structural Steel
6. Foundations
7. Auxiliary Power Supply
8. Electrical Feed to Power Distribution Center
9. Plant lighting
10. DCS Interface
11. Upgrading of CEMs
12. Fire Protection
13. Demolition and relocation of existing equipment

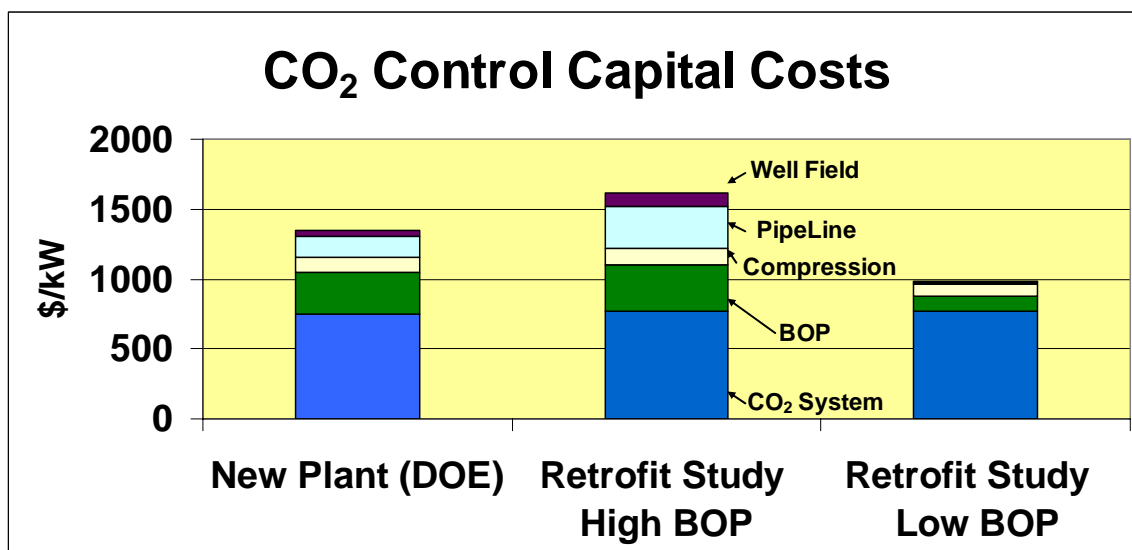
This site was considered a “difficult” retrofit location. The CO<sub>2</sub> removal system could not be located close to the existing wet-stack. Therefore a space was identified in the middle of the coal yard as the closest location. Much of the coal storage area would need to be replaced. The distance for the main interconnection with the vendor facilities was a large distance from the stack.

The single most expensive item was the ductwork to and from the unit. The ductwork represented about one-half of the BOP cost. Although the cost of a new stack is less than one-half the cost of ductwork, installing only a one-way duct would cost more than one-half the estimated costs. Therefore the savings associated with a new wet stack would not be less than installing the return duct.

Steam piping was especially expensive, with the steam pipe of a larger diameter than the crossover to minimize pressure drop. Steam piping requires expansion loops, so the amount of pipe required is more than the specific distance from the turbine room to the regeneration system.

Another added cost not typically considered is the installation of a demineralizer system on the condensate. S&L does not recommend reusing condensate that has been used for a “process” application unless it has been treated to avoid contamination of the boiler feed water. This was added near the CO<sub>2</sub> scrubber system where adequate space was available.

The specific results from the study are confidential, but the results have been compared to capital costs reported by DOE for 90% CO<sub>2</sub> removal for 100% of a new plant’s flue gas. These costs (escalated to 2008\$) are about \$1350/kW.<sup>1</sup> This is for the overall facility investment and includes certain assumptions for BOP compression and sequestration. Based on this paper, it was important to consider the elements of the study and determine those factors that can vary from site to site. Thus we find that on the same basis of 90% capture of 100% of the flue gas, the normalized cost for the CO<sub>2</sub> recovery system is about \$770/kW. The BOP, pipeline, well field, and CO<sub>2</sub> compression costs however can vary somewhat based on site specific factors. A high and low-range estimate was developed to show how these costs can vary for different applications.



<sup>1</sup> Cost and Performance Baseline for Fossil Energy Plants; DOE/NETL-2007/1281

S&L has concluded that BOP costs for a typical plant could range from about \$100 to \$350/kW depending on the distance of the facility from the power plant and the relative difficulty of retrofit. For plants where the CO<sub>2</sub> system can be located very close to a wet-FGD system and wet stack, the costs will be on the lower end of the range. For sites that require a substantial distance and/or demolition costs the results will be nearer the high end.

The costs for CO<sub>2</sub> compression, pipeline, and well field were not a part of S&L's original study scope. These costs were estimated for inclusion in this paper.<sup>2</sup> The compression costs are generally proportionate to the amount of CO<sub>2</sub> removed. For a plant of this size, a cost ranging from \$85 - \$120/kW was used. Pipeline costs can vary significantly depending on distance (from less than 1 mile for on-site sequestration to hundreds of miles for EOR application) and the size of the pipeline. To determine a reasonable range 1-mile and 100 miles was used at a cost of about \$975,000 per mile. This yields costs ranging from about \$3 to \$300/kW for plants of about a 500 MW plant. Similarly, well field costs can vary considerably depending on the geology and quantity of CO<sub>2</sub> disposed of over the lifetime of the field. For the purposes of this paper a range of \$20 – \$100/kW was developed.

The overall capital costs generally straddle the costs identified in the DOE Study for a plant providing about 500 MW net out put.

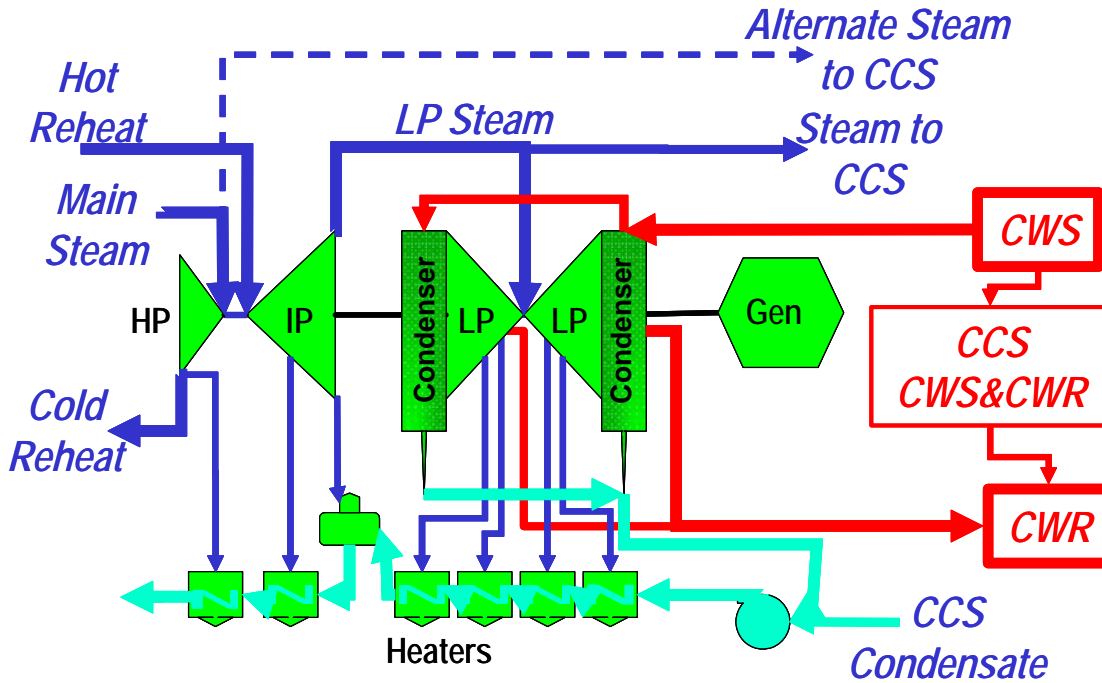
## Plant Performance

The plant performance is greatly impacted by extracting significant quantities of steam from the IP/LP input to the LP steam turbine. Cooling water is also required and can be extracted from the cooling water supply system. A preliminary analysis determined that extraction of steam associated with scrubbing just one-half of the flue gas could be accomplished without deleterious impacts to the steam turbine.

A GATE CYCLE model was developed to identify the performance of the plant under varying operating conditions to determine the impact on the plant. Care was used to ensure that the steam pressure delivered to the CO<sub>2</sub> system did not fall below their requirements and that the steam pressure to the turbine did not fall below its needs. Key issues for the turbine are sufficient steam to adequately cool the turbine and to meet the pressure requirements at the condenser. In the event the LP steam cannot meet these criteria, HP steam must be used to operate the CO<sub>2</sub> system. The Figure below provides a diagram of the integration of the CO<sub>2</sub> system with the steam cycle.

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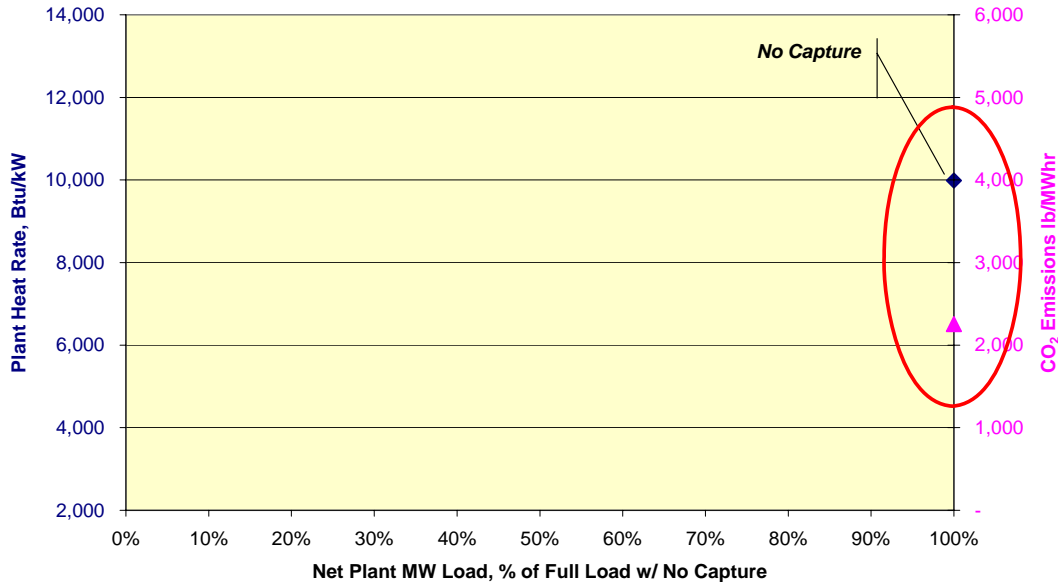
<sup>2</sup> Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity; David L. McCollum and Joan M. Ogden; Institute of Transportation Studies, University of California Davis; 2006



CWS = Cooling Water Supply      CCS = Carbon Control & Sequestration  
 CWR = Cooling Water Return

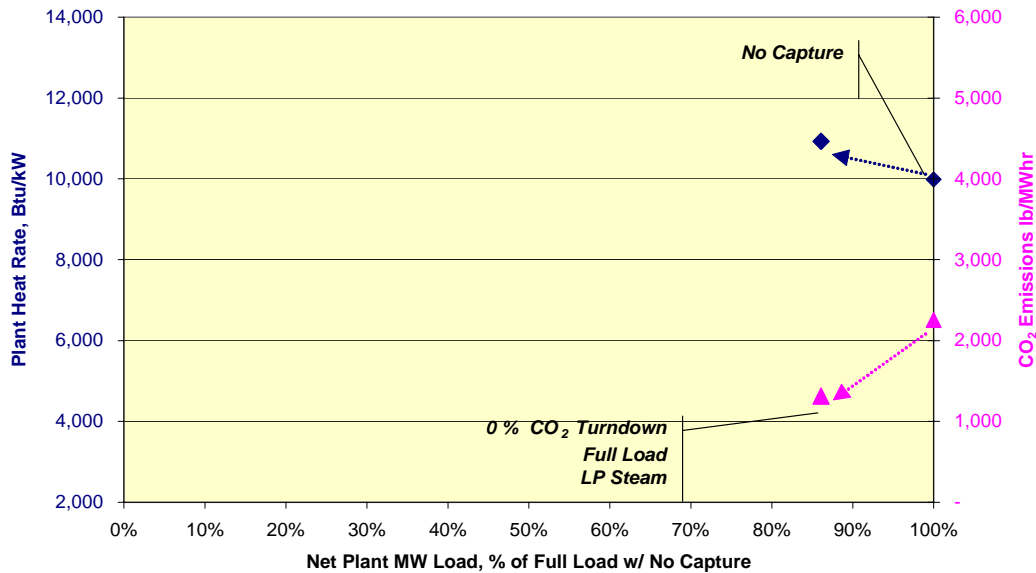
The following series of graphs provide the results of the modeling effort associated with the operation of the CO<sub>2</sub> system at varying loads. Each graph compares both the heat rate of the unit and the emissions on a pound per MW basis against the “X” axis which shows the relative output of the unit compared to full load net output. The first graph indicates the performance of the plant without the CO<sub>2</sub> system in service. The plant heat rate is just under 9,990 Btu/kW and the emissions are about 2,255 lb/MW at full load.

**CO<sub>2</sub> Capture Impact on Plant Performance**  
**Comparing Maximum Capture vs. Turndown of Scrubber System**  
**Capture System Designed for One-Half of Gas Flow**



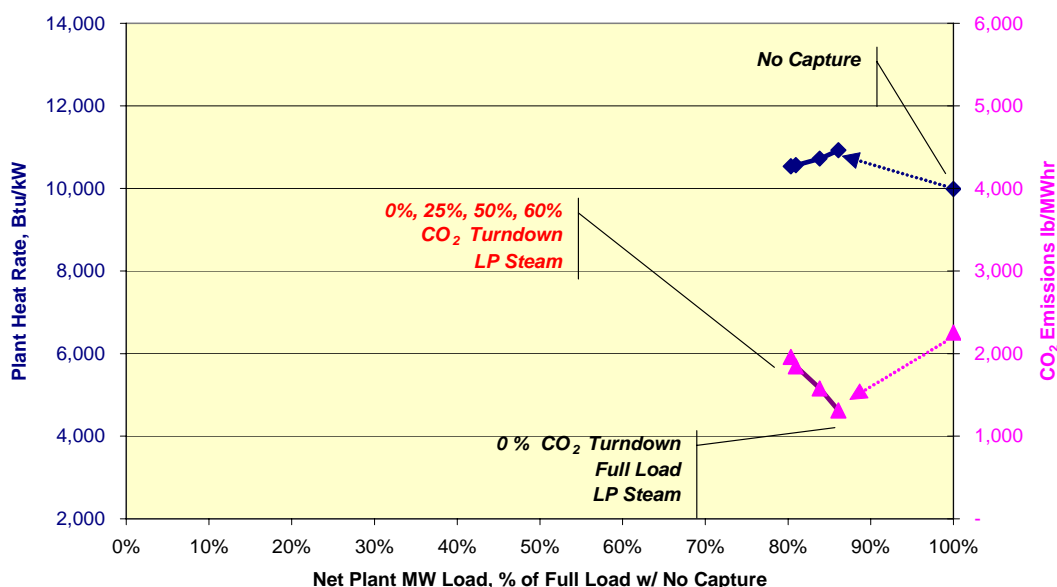
Next, we show the impact of turning the CO<sub>2</sub> capture system on at full load. Note that the plant output drops by about 14% (with one-half the unit being scrubbed). Plant heat rate increases to 10,925 Btu/kW while CO<sub>2</sub> emissions are reduced about 1,310 lb/MW.

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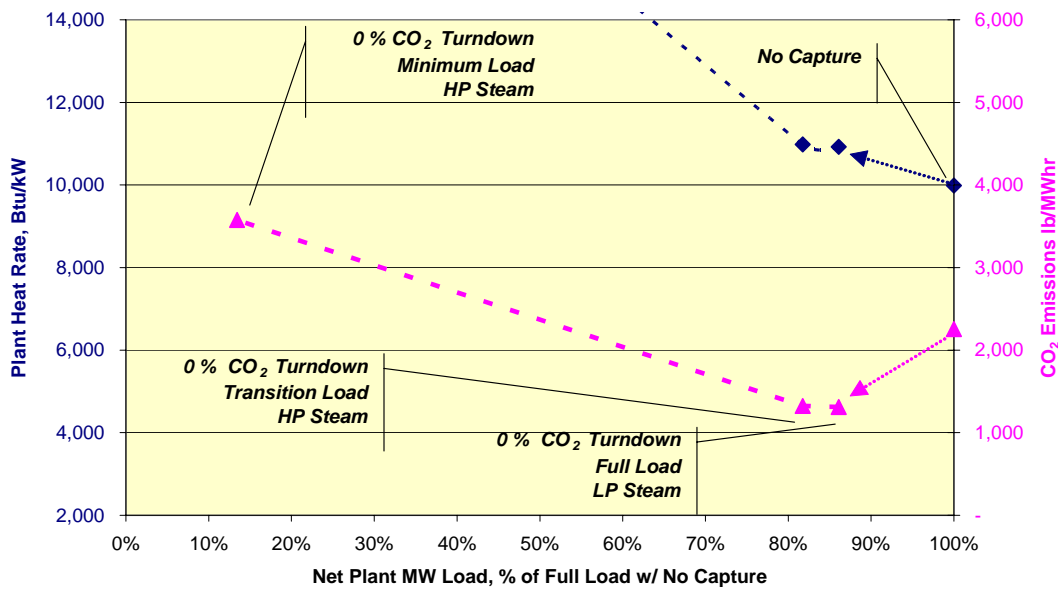
The next graph shows what happens as the plant is turned down with IP/LP steam must be used to supply the stripper to regenerate the CO<sub>2</sub> solvent. In order to maintain a safe operation of the steam turbine, the CO<sub>2</sub> system must also be turned down. Operation points at 0% (full load), 25%, 50%, and 60% (40% throughput) turndown are indicated. At the 60% turndown or 40% throughput, we are at the minimum operating point for the CO<sub>2</sub> scrubbing system. Under these conditions, the boiler is operating load has been reduced to only 80% of net output. This represents an 8% operating range from full removal to 40% removal. Although the heat rate improves during these conditions from the full load operation, CO<sub>2</sub> emissions increase to 1,710 lb/MW.

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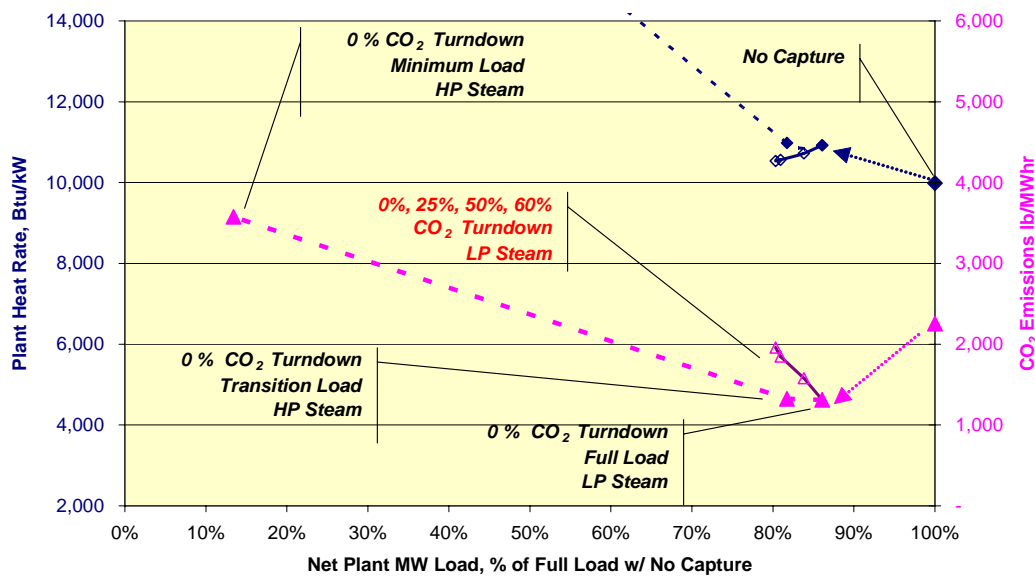
The next issue is the impact on the plant of maintaining full flow through the CO<sub>2</sub> system. This is shown in the next graph. At the 82% load condition, the steam pressure and flow is no longer acceptable from the IP/LP. Now the steam supply must be switched to main steam. The use of main steam imposes a huge penalty on the power plant. The heat rate skyrockets, and the emissions of CO<sub>2</sub> increase dramatically. At about 50% net output, the emissions exceed 2,200 lb/MW and are about the same as the emissions from the plant if no CO<sub>2</sub> were captured at all. This outcome was not expected when we began the study.

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The overall impact is summarized in the next graph which compiles the data from each step into one picture.

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These impacts suggest that it will be necessary to run the plant at nearly full load at all times to have any benefit from a CO<sub>2</sub> capture system. This is obvious since reducing plant load only

increases the relative emissions on a pound per MW basis rather than further reducing the impact. Removing the CO<sub>2</sub> just to send it to a disposal site is not the goal, rather the goal is to reduce the “foot print” or CO<sub>2</sub> emissions per MW dispatched. This is the true measure of the technology since MW not generated (consumed in the process) must be made up someplace else.

## **Conclusions**

The overall capital costs for amine based CO<sub>2</sub> capture systems are greatly dependent upon the site specific aspects of the installation. In general, the DOE reported costs can be used as a guide for general planning purposes. Since no commercial utility scale plants have actually been designed, detailed cost estimates for the technology are very speculative.

The impacts of CO<sub>2</sub> capture systems can greatly limit the degrees of freedom associated with the operation of a specific generating plant. A plant with these systems retrofit will likely need to operate at near full capacity in order to optimize the capture from the facility. The use of high-pressure steam is impractical due the severe penalties imposed on the plant performance. Therefore, turndown of the plant needs to be carefully studied to fully evaluate the impacts on the overall operations. This may be true for complete scrubbing of the flue gas or even with partial scrubbing of the flue gas as was the case in the example presented here. Turning down the CO<sub>2</sub> capture system at partial load can mitigate heat rate concerns to some extent, but should be studied in detail for each specific retrofit application.

It must be remembered that these findings are very specific to the specific amine based technology studied and the plant to which the technology is retrofit. Other CO<sub>2</sub> capture technologies may have a broader leeway on steam specifications and demand which would expand the operating window for turndown.

Advanced technologies currently being developed across the industry will need to be studied carefully and individually to understand their utility requirements and the impacts of their integration into a specific power plant. These new technologies are expected to have a much lower steam and auxiliary power demand that will make them easier to integrate as a retrofit for existing facilities. The results of their pilot operations should be observed with keen interest.