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# IGCC - THE CHALLENGES OF INTEGRATION

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## ABSTRACT

IGCC (Integrated Gasification Combined Cycle) promises to provide a large share of the future world energy needs in an economical, reliable, and environmentally friendly way. Over the last 20 years, manufacturers have made significant strides in developing better, cost-effective products: gasifiers, air separation units, gas turbines, steam turbines, syngas cleanup processes, etc. However, to insure successful and reliable operation, all the above components need to be harmoniously integrated, both from a design standpoint and throughout project execution. This paper describes the challenges of the integration processes from an EPC contractor's perspective. The discussion first covers IGCC configuration optimization including gas turbine integration with other plant units. Several project planning and execution phase strategies unique to IGCC are then discussed. Finally, the paper describes a strategy that will continue to increase the efficiency, drive down the cost, shorten the EPC schedule, and improve the availability of future generations of IGCC plants. [*Keywords:* IGCC, gasification; plant configuration integration]

## INTRODUCTION

Integrated gasification combined cycle (IGCC) technology offers a clean, efficient option for producing electricity from coal and other low-cost fuels. The gas turbine combined cycle enables the high IGCC efficiencies, while the gasification block cleanly converts the coal to fuel for the gas turbines. Proper technical and organizational integration of IGCC projects throughout project implementation is key to achieving the customer's objectives for heat rate, capital cost, schedule, and operating dependability. This paper provides some insights into the sometimes-daunting integration issues and provides some suggestions for achieving the optimal solution.

## IGCC OVERVIEW

Most recent, commercial IGCC projects have coupled E-class or F-class gas turbines with entrained flow gasification processes such as those of General Electric. This paper focuses on such applications for this reason, and because Bechtel and General Electric have created an IGCC alliance targeted at the US utility market.

Figure 1 shows the basic components of a typical IGCC design with an emphasis on the streams flowing between the components, i.e., the integration.

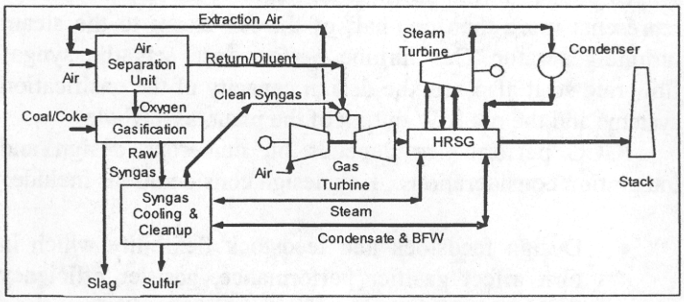


**Figure 1 –Typical IGCC Flow Diagram**

In the gasification process, coal and/or petcoke react with high purity oxygen at 3-7 MPa (430-1,000 psig) and typically >1,100°C to produce a combustible fuel (syngas). An air separation unit cryogenically separates the oxygen from nitrogen and compresses it to gasifier pressure. The syngas, once cooled in the syngas cooler(s) and then cleaned of flyash and sulfur species, combusts in and expands through the gas turbine. In the diagram, compressed nitrogen from the air separation unit flows to the gas turbine combustors for $NO_x$ reduction. Numerous feed water, steam, and condensate streams may flow between the gasification and combined cycle systems to optimize the various heat sinks and sources.

Table 1 summarizes the key plant performance and emissions from an IGCC plant design that GE and Bechtel offer. The values reflect a design using Illinois Basin coal and GE 7FB gas turbines. The values will vary for other IGCC designs with different coals, processes, and emissions requirements.

| | |
|---|---|
| Nominal Plant Output | 600 MW |
| Heat Rate | 8,650 Btu/kWh (HHV) (39.4% eff.) |
| HRSG Stack Emissions (sum of 2 stacks) | |
| $NO_x$ | 0.02 lb/MMBtu *(5 ppmvd @15% $O_2$)* |
| $SO_x$, | 0.02 lb/MMBtu |
| CO | 0.034 lb/MMBtu |
| UHC | 0.006 lb/MMBtu |
| PM | 0.01 lb/MMBtu |

**Table 1. IGCC Plant Performance and Emissions**

## KEY DESIGN AND INTEGRATION VARIABLES

Proper design integration involves a trade-off of overall plant efficiency, capital cost, operability, availability, and physical constraints of selected equipment and processes. Design optimization should start with and hinges upon the selection of the gas turbine(s). It is the largest power generator, converting the chemical energy and sensible heat in compressed syngas into power and hot gas turbine exhaust. The exhaust gas, typically at about 600°C for F-class machines, serves as the primary source of high level energy for superheating and reheating high pressure (HP) steam from the syngas coolers in the gasification plant. This steam typically represents more than one-half of the HP steam to the steam turbine-generator. Gas turbine performance sets the syngas flow rate so it also sets the design capacity of the gasification systems and the net MW output of the plant, as a whole.

IGCC performance depends on numerous design and integration considerations. Key design considerations include:

- Design feedstock and feedstock flexibility which in turn affect gasifier performance, gasifier efficiency (cold gas efficiency), and syngas composition
- Design ambient conditions and site elevation
- Gas turbine design features and operating envelope
- Overall plant efficiency targets and the trade-off with capital cost
- Waste water discharge guidelines (affects auxiliary load)
- Emission limits or standards

Integration considerations include:

- Gas turbine air extraction to the ASU
- $NO_x$ control strategy
- Gas turbine power augmentation
- High temperature heat recovery integration
- Low temperature heat recovery integration
- Steam generation conditions
- Utility balance
- Brownfield site and use of existing equipment
- Co-production or polygeneration including steam, hydrogen, and other products

Because of the interdependence of the various integrated plant areas, integrated IGCC design typically requires close coordinated design between the gas turbine supplier, the gasification licensor and ASU supplier.

## INTEGRATION OF IGCC PROJECTS TO-DATE

The first IGCC plant, the Cool Water Coal Gasification Program, employed the Texaco (now GE) gasification process to fuel a GE 7E gas turbine-based combined cycle. Refer to Figure 2. The design used syngas moisturization for $NO_x$ control and included radiant and convective syngas coolers, and BFW economizers. Steam superheating was done in the HRSG because of the high cost of superheating steam with hot, particulate laden, sour syngas. Early in the plant operation the economizer was taken out of service.

Tampa Electric's Polk Power IGCC plant uses nitrogen for GE 7FA gas turbine $NO_x$ control (Figure 3). The nitrogen is provided by a medium pressure design ASU, which maximizes summer plant power output and minimizes water consumption at the expense of increased auxiliary power requirements. Recently Tampa Electric added syngas moisturization to meet tightened $NO_x$ control requirements. Saturated HP steam from the radiant and convective syngas coolers is superheated in the HRSG. The design originally included efficiency-enhancing gas-gas heat exchanger downstream of he syngas coolers for clean syngas and diluent $N_2$ heating. However, Tampa Electric later removed them due to poorer-than-expected operating and maintenance experience.

Global Energy's Wabash River IGCC plant, based on ConocoPhillips' E-Gas gasification process, employs a syngas cooler to generate saturated HP steam that is superheated in the HRSG (Figure 4). The GE 7F gas turbine $NO_x$ emissions are controlled using syngas moisturization followed by MP steam injection .

The Nuon IGCC plant in The Netherlands uses the Shell gasification process and a Siemens V94.2 gas turbine. Moisturization of mixed syngas and nitrogen control $NO_x$ emissions (Figure 5). All of the air to the ASU comes from gas turbine air extraction.

The Elcogas IGCC project in Puertollano, Spain uses the PRENFLO gasification process and a Siemens V94.3 gas turbine. It has a similar design to the Nuon plant except that the $N_2$ flows separately to the gas turbine and is not moisturized.

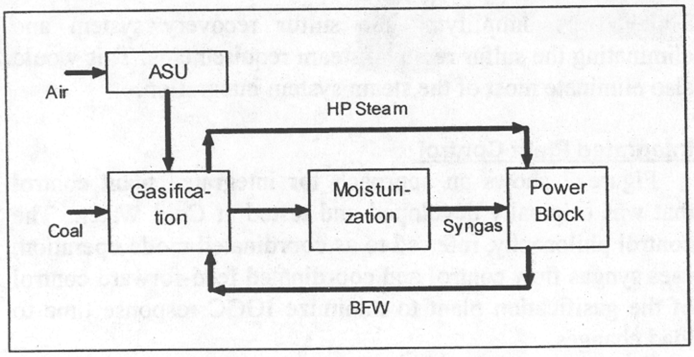


**Figure 2. Integration Diagram for the Cool Water Project**

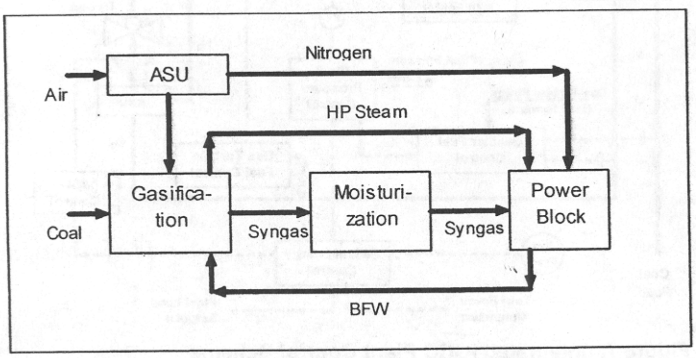


**Figure 3. Integration Diagram for the Polk Power Project**

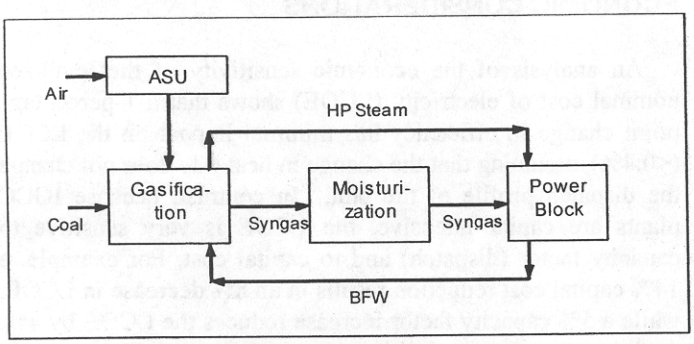


**Figure 4. Integration Diagram for the Wabash River Project**

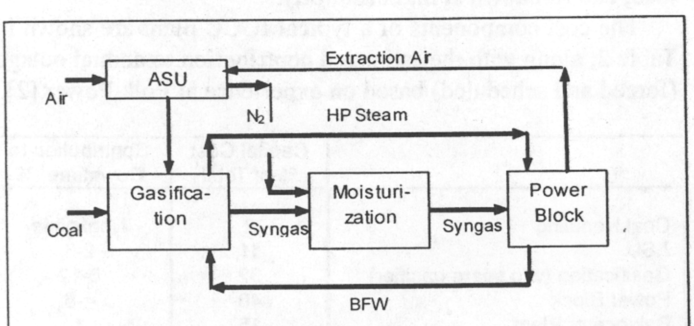


**Figure 5. Integration Diagram for the Nuon Project**

## DESIGN INTEGRATION

### ASU and gas turbine air integration

Syngas is a low-Btu fuel (nominally 250 Btu/scf, HHV) that can add significant mass flow to the gas turbine when compared to natural gas firing. Most gas turbines are optimized for natural gas performance so when firing syngas they have more air compressor capacity than needed. The extra mass flow can boost output up to the limits of the gas turbine expander flow, firing temperature, and expander blade materials. Starting with an estimate of syngas composition and temperature and $NO_x$ control diluents, the gas turbine supplier can optimize gas turbine performance.

Similarly, it is economically beneficial to use all of the nitrogen ($N_2$) available from the ASU. However, $N_2$ availability is a function of oxygen production, which in turn depends on coal feedstock and gasifier performance, and furthermore co-production of $N_2$, hydrogen, methanol, Fischer-Tropsch liquids, or other products. Therefore, $N_2$ availability (as well as syngas and/or $N_2$ moisturization) may change as the gasification plant design develops. This would affect gas turbine performance setting up a gas turbine-gasification plant-ASU design iteration loop.

Adding $N_2$ and/or moisture to the maximum level possible is called power augmentation and results in a combustor fuel heating value approaching 110 Btu/scf. For gas turbines designed specifically for natural gas fuel this requires significant air extraction. Depending on the design of the machine, this extraction may provide all of the compressed air required by the ASU. The GE 7FA gas turbine can accommodate some of the extra mass flow and boost power output by about 15%. However, they would still require air extraction and provide up to 50% of the ASU air. This design would be easier to startup and operate than a 100% integrated design as demonstrated at Nuon and Puertallano.

Figure 6 shows the results of a recent study of IGCC plant heat rate versus percent of ASU air provided by air extraction. For this study, providing 25% of the ASU air requirements by gas turbine air extraction resulted in the maximum plant output. However, this is likely to change with improving gasification plant, ASU and gas turbine performance and, therefore, should be evaluated for each project.

### Gas turbine $NO_x$ emissions control strategy

As noted above, $N_2$, moisture, steam, and/or $CO_2$ can be used as $NO_x$ control diluent. Diluent must be supplied at the conditions specified by the gas turbine supplier. Today most designs appear to focus on $N_2$ and moisturization to minimize water consumption and to maximize recovery of low level heat.

### Gasifier syngas cooler steam integration with the HRSG

HRSG's in highly integrated IGCC designs are approaching the point where the syngas cooler is the HP boiler for the

HRSG, which does the steam superheating, reheating and BFW economizing for the steam bottoming cycle. In this case it is

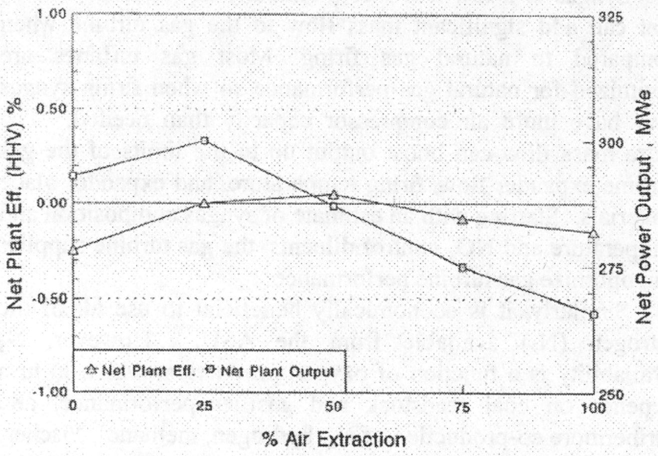


**Figure 6. Example of the Effects of Air Extraction on Gas Turbine Performance**

important to provide boiling surface in the HRSG for the various steam levels to allow operation of the steam cycle firing the gas turbine on backup fuel.

**Heat recovery within the gasification unit**

The basics of heat recovery and thermal integration were addressed in a recent technical paper [1]. The paper suggests matching heat sources shown in a composite syngas and gas turbine exhaust cooling curve with process and power generation heating requirements. This should be done using a pinch or exergy analysis to maximize power output while considering the cost impact.

Moisturization of syngas and/or $N_2$ for $NO_x$ control provides an economical way to use low-level energy in the low temperature gas cooling section of the gasification plant. Therefore, it is desirable work with the gas turbine supplier to define the level of moisturization when providing the syngas composition.

**Upstream sulfur control (integrated $SO_2$/$NO_x$ solution)**

Sulfur compounds in the syngas are oxidized to $SO_2$ in the gas turbine combustor and leave the system in the gas turbine exhaust. $SO_2$ affects the acid dew point of the exhaust which in turn affects the allowable stack temperature and materials. Also, low sulfur syngas ($\leq$20 ppmv total sulfur species) is required to permit operation of a SCR without significant fouling from ammonium sulfate compounds. Achieving very low sulfur syngas typically requires COS hydrolysis combined with acid gas removal using a physical solvent or a mixed solvent.

Technologies are being developed for syngas sulfur removal, which have the potential to reduce capital cost by up to 10% and increase plant efficiency by 1%. This can be achieved by simplifying the sulfur recovery system and eliminating the sulfur removal steam requirements. This would also eliminate most of the steam system integration.

**Integrated Plant Control**

Figure 7 shows an approach for integrated plant control that was originally developed and tested at Cool Water. The control philosophy, referred to as coordinated mode operation, uses syngas flow control and coordinated feed-forward control of the gasification plant to minimize IGGC response time to load changes.

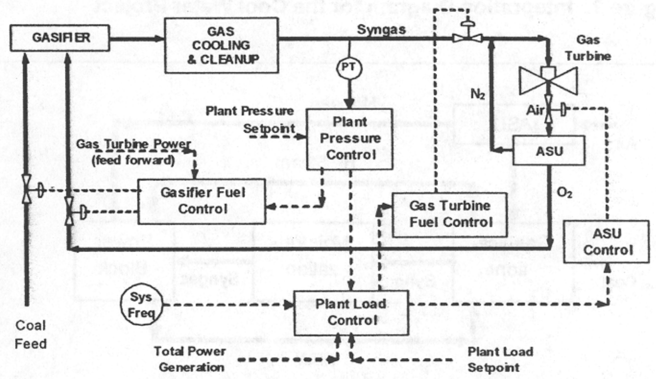


**Figure 7. Integrated IGCC Plant Control Scheme**

## ECONOMIC CONSIDERATIONS

An analysis of the economic sensitivity of the levelized nominal cost of electricity (LCOE) shows that a 1 percentage point change in efficiency has minimal impact on the LCOE (<0.4%), assuming that the change in heat rate does not change the dispatch profile of the unit. In contrast, because IGCC plants are capital-intensive, the LCOE is very sensitive to capacity factor (dispatch) and to capital cost. For example, a 14% capital cost reduction results in an 8% decrease in LCOE, while a 5% capacity factor increase reduces the LCOE by 4%. Additionally, the operating characteristics of IGCC plants make them best suited to applications where they operate base-load, and turndown at night (not off).

The cost components of a typical IGCC plant are shown in Table 2, along with the estimated contribution to annual outage (forced and scheduled) based on experience at Polk Power [2].

| | Capital Cost % of Total | Contribution to Downtime, % |
|---|---|---|
| Coal Handling | 2 | Negligible |
| ASU | 11 | 2-3 |
| Gasification (w/o spare gasifier) | 32 | 8-12 |
| Power Block | 40 | 4-6 |
| Balance of Plant | 15 | 1 |
| Total | 100 | 15-20 |

**Table 2. IGCC Capital Costs and Availability Effects**

The gasification block is clearly a high cost area with a high availability impact. Significant improvements should result as more IGCC plants are brought online. While both forced and scheduled outage rates can be reduced with a spare gasifier, the capital cost increases by $100-150/kW. Spare gasifier economic benefits will likely decrease as plant operators gain experience and reduce down time. A lower initial cost, but higher operating cost alternative is to provide a backup fuel for the gas turbine. This approach also simplifies the gasification system design by eliminating the piping and valving required to integrate the spare gasifier train into the IGCC plant.

The combined cycle plant also represents a large portion of the capital cost. However, as a fairly mature technology, the opportunities for significantly improved cost and availability are limited.

## PROJECT IMPLEMENTATION

Figure 8 shows a high-level schedule for an IGCC project from initial owner evaluations through commercial operation. The critical path flows through preliminary engineering (FEED or front-end engineering and design); permitting; long-lead equipment design, fabrication, and installation; and commissioning/startup. This particular schedule assumes that the owner commits to long-lead equipment prior to the EPC contractor's notice-to-proceed, and that the gasification syngas coolers (not the gas turbines) are critical path.

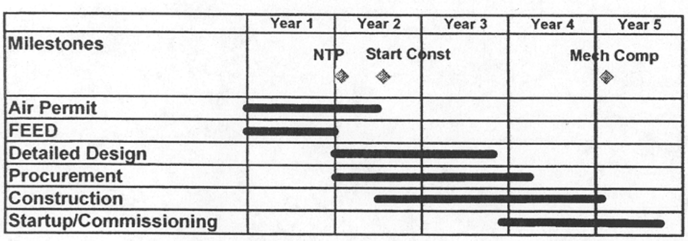


**Figure 8. Typical IGCC Project Schedule**

Compared to that of gas-fired combined cycle units and even pulverized coal-fired units, IGCC project development currently requires the owner to make more and earlier decisions related to technology, equipment, and project participants – typically with limited in-house knowledge on the risks and consequences of these decisions. This situation will improve as the IGCC market matures, and more specifically, through design replication and use of reference plant designs. Key decisions include the following:

- Selection of the gasification technology, gas turbine, basic integration approach and $NO_x$ control strategy must be completed prior to or as part of the BACT assessment, the air modeling, and the permit applications. These decisions affect: number, characteristics, and locations of continuous emissions points; overall IGCC plant capacity, heat rate, emissions control options, and emission characteristics; and overall plant water balance
- Early selection of a strong, integrated team approach is necessary because IGCC projects involve comparatively more project players: industrial gas company providing air separation unit, gasification technology provider, EPC contractor, and vendors of highly-engineered equipment such as turbine-generators and syngas coolers.
- The most unpredictable startup activities concern shakedown of gasifier and gas processing systems and initial operation of the gas turbines on syngas. Early ASU startup and startup of the power block on natural gas ensure they stay off the critical patch.
- The integrated plant controls including the gasifier safety shutdown and control systems must be thoroughly checked prior to first syngas production. Small programming glitches can significantly delay startup because of the time needed to prepare for each gasifier light-off.

## THE REFERENCE PLANT APPROACH

IGCC's design flexibility and resulting complexity has to some extent been an impediment to the growth of the IGCC market. The few IGCC projects to date have been built as one-off designs, each customized to the specific situation with varying degrees of new technology and configuration complexity. Some projects have been very successful, while others have not achieved expected cost, schedule, and performance targets. The outcome has not been predictable. In response, gasification technology providers are beginning to align with EPC contractors and other project participants. For example, General Electric and Bechtel have formed an alliance to develop and implement optimized, coal-based IGCC reference plant designs. Development and replication of a reference plant design will drive down capital costs, increase certainty of outcome (with commercial guarantees), reduce project development costs and schedule, and facilitate implementation of a program for future product enhancements.

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