


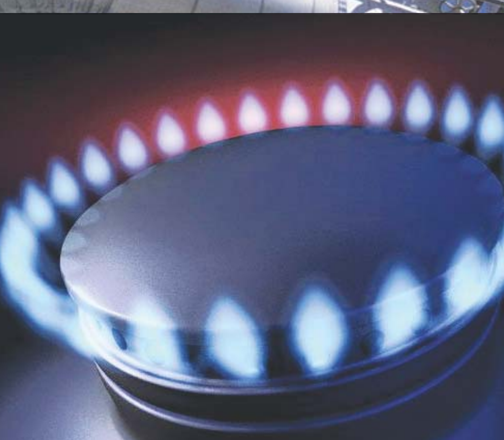

U.S. Department of Energy
Office of Fossil Energy

Practical Experience Gained During the First Twenty Years of Operation of the Great Plains Gasification Plant and Implications for Future Projects

April 2006

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EXECUTIVE SUMMARY

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota has operated successfully for 20 years as the only commercial coal-to-natural gas facility in the United States. The experience gained during those 20 years has created an opportunity to benefit from a fully proven technology base. This document is intended to capture what the first 20 years of the plant's operation has taught operators about a synthetic natural gas from coal production facility. This information is expected to aid in the design, construction, and operation of future coal gasification facilities.

The plant's success has not been achieved without some changes and alterations over its lifetime. The sources for this report, which include past technical reports and interviews with plant operators and managers, revealed that most parts of the original plant design worked well, but a few did not. Many processes in the plant have undergone redesign, repair, or improvement. These changes have made the plant much more productive, efficient, and environmentally sound than even its designers envisioned.

From 1984 through 2005, the Great Plains Synfuels Plant has produced pipeline-quality synthetic natural gas on 7,725 days out of 7,828 days (98.7%) since it began operations. Remarkable technical and financial benefits have resulted from this exceedingly consistent long-term operation.

However, a few alterations to the plant did not deliver the results that the designers had expected. Both the successes and occasional setbacks taught the operators valuable lessons about the capabilities and limitations of the plant and the technology on which it is based. These lessons learned can be of value to future coal gasification efforts.

Some examples of design elements which required later changes include the primary coal crushers; the boiler fuel mix and configuration; the gasifier grates; ash handling systems; the flare and liquid waste incinerator systems; the rectisol tower trays; and the product compression turbines. One early problem with the original plant design, which caused substantial subsequent changes to the plant, was repeated problems with the Stretford sulfur recovery unit. Engineers experimented by replacing the unit with a sulfolin unit, but this proved unsuccessful. Eventually, acid gases were re-routed to the boilers and an ammonia scrubber was added for flue gas desulfurization.

Over the years, the plant has diversified to produce a broader slate of secondary products. In the late 1990s, an ammonia synthesis unit was added to the plant to produce anhydrous ammonia for fertilizer. In addition, the ammonia scrubbers on the boiler emissions are used to produce ammonium sulfate, which is also marketed as agricultural fertilizer.

The plant is the first energy facility to separate and sequester carbon dioxide (CO_2) emissions from a coal process, delivering the waste gas through a 205-mile pipeline to a mature oil field in Saskatchewan, where it is sold for injection into wells for enhanced oil recovery and storage. More than five million tons of CO_2 have been sequestered to date, while doubling the oil recovery rate of the oil field. The success of the Dakota Gasification Company/Encana sequestration project is being carefully monitored by scientists around the world.

All of the changes to the plant have served to modernize and optimize processes, and some — like the CO_2 project — have allowed the plant to continue to pioneer new technologies, even in its third decade of operations.

Fred Stern, the plant's manager, has noted that the plant consists largely of 1970s technology that has taken a long struggle to perfect. For example, the fixed-bed gasifiers used at the present plant are a proven, reliable technology. They have proven extremely robust and effective, allowing the plant to deliver synthetic natural gas on 7,725 days out of 7,828 days since its commissioning, with only 103 days of inactivity over 20-plus years. However, many plant operators and managers point to emerging gasification technologies that will gasify coal without producing the low-quality gas liquor streams that must be processed and cleaned at the GPSP.

The challenges of refining plant processes to maximize production are undoubtedly similar to what the engineers responsible for the next generation of coal gasification facilities will face. Therefore, the numerous innovative approaches, bold actions, and effective solutions authored at the GPSP can help ensure the nation's energy future.

The success of the plant and its synergies with power plants, coalmines, oil fields, and potentially other energy-related activities, combined with the rising prices of natural gas, make coal gasification a key element of future energy production. Nowhere has coal gasification on the commercial scale been perfected over time as it has at the Great Plains Synfuels Plant.

"The success of the Weyburn Project could have incredible implications for reducing CO_2 emissions and increasing America's oil production. Just by applying this technique to the oil fields of Western Canada we would see billions of additional barrels of oil and a reduction in CO_2 emissions equivalent to pulling more than 200 million cars off the road for a year. The Weyburn Project will provide policymakers, the energy industry, and the general public with reliable information about industrial carbon sequestration and enhanced oil recovery."

– Samuel Bodman
Secretary of Energy

November 15, 2005

1. Purpose

The Dakota Gasification Company's synfuels plant in Beulah, North Dakota, is truly a national asset. This commercial plant has operated successfully for 20 years, and the experience gained brings us opportunities to benefit from a fully proven technology base. This document is intended to capture, as much as possible, what the first 20 years of the plant's operation has taught operators about a synthetic natural gas from coal production facility.

2. Scope

This document includes researched technical information from the following sources: the building and commissioning of the GPSP, measures taken by plant operators to improve plant performance and efficiency, knowledge gained during the 2004 planned plant shutdown, and from additional sources that could reasonably be expected to aid in the design, construction, and operation of a future coal-to-natural gas facility. Information is presented on each major process area of the plant, and includes facts about what was intended to happen, what actually did happen, and what are the implications of this operational history for future coal-to-natural gas facilities.

This document does not make recommendations; rather, it attempts to provide background of operational history of the GPSP and some operators' thoughts on implications for future similar facilities. The researched information includes both general and specific data on gasification technology and its associated plant processes, physical layouts, and requirements. It draws heavily from earlier analytical reports including one developed by Fluor Technology, Inc. in 1988, entitled *Great Plains Coal Gasification Plant/Technical Lessons Learned Report*. It also includes opinions expressed to the authors by professional personnel involved in the construction and/or operation of the plant. Much of this comes from interviews with senior managers and staff of the DGC, Basin Electric Power Cooperative (BEPC), and the U.S. Department of Energy's (DOE's) Office of Fossil Energy (FE). The intent is to revisit issues presented in the Fluor report as well as other documents to determine what more has been learned in the ensuing 17 years of operations, and to identify how those issues and any new problems or solutions regarding plant operations can be related to future projects. As with most surveys, feedback concerning the future can differ significantly. Where such differences or ranges of answers were noted, they are presented for consideration without attribution or recommendation in this document. Any opinions do not necessarily reflect the views of DOE, DGC, BEPC, Technology & Management Services, Inc. (TMS), or the authors.

This document is not intended to provide economic analysis of whether or not coal gasification is viable in certain locations, or to necessarily promote coal gasification as a technology. Product markets and potential revenues are not calculated or addressed. It is also not intended to contain information that is proprietary to the DGC, Lurgi AG, or any other entity. Some discussion of knowledge gained during the planning and construction of the plant is included. However, it is the experience of operating the plant for 20 years that gives many of the DGC operators and managers a perspective that is unique in the industry, so knowledge gained during these pre-operational phases is confined to an appendix.

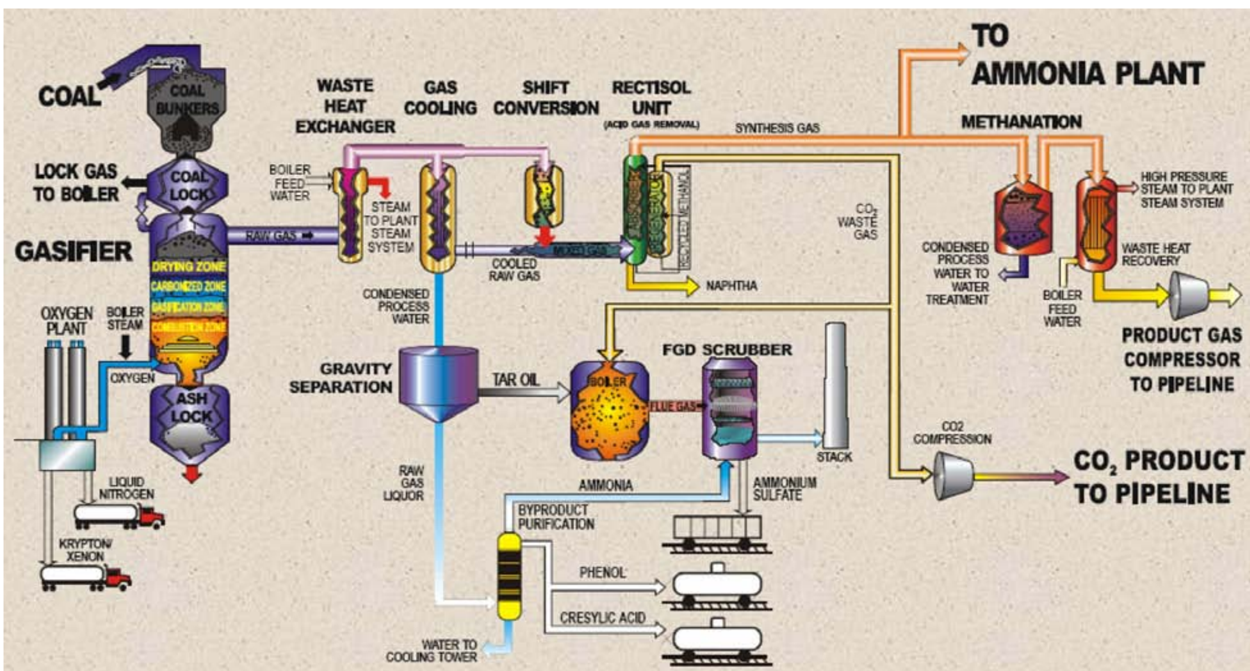
3. Twenty Years of Operation

The GPSP plant converts North Dakota lignite into other high value energy products. The main plant product is pipeline-quality Synthetic Natural Gas (SNG), with a heating value of about 972 Btu/scf. Other products include carbon dioxide, anhydrous ammonia, ammonium sulfate, krypton, xenon, dephenolized cresylic acid, liquid nitrogen, naphtha, and phenol.

In 1999, the plant became one of the first commercial facilities to sequester carbon emissions when it began delivering a 95 percent pure stream of CO_2 through a newly constructed pipeline to an oilfield in Saskatchewan. There the CO_2 is injected into the mature Weyburn Oil Fields for enhanced oil recovery (EOR). Oil recovery from the fields has been significantly enhanced, and efforts are underway to expand CO_2 deliveries.

The plant process is depicted in simplified form in Figure 1, below. This graphic is not a complete representation of every system or material flow in the plant, but rather a general flow chart of the process. For example, the main product train flowing through the plant is actually divided into two process trains. More detailed descriptions of the plant and its various processes and components are found later in this report.

Figure 1: Simplified Process Diagram



Picture courtesy of DGC

The plant has operated successfully and efficiently for over 20 years. Remarkably, the plant ran nearly continuously from its commissioning until a planned shutdown in June 2004. During that time, modifications were undertaken that have resulted in the plant producing a greater output of products and achieving greater efficiency than had been expected by the plants designers. Over the period culminating in the planned shutdown in 2004, these modifications have increased productivity by about 41 percent over designed specifications. Designed to produce 125 million standard cubic feet per day (mmscfd) of natural gas, by 1992 the plant was routinely delivering nearly 160 mmscfd, and in recent years has delivered as much as 165 to 170 mmscfd. Initial results from changes made during the June 2004 plant shutdown suggest production has significantly improved, with some days exceeding 170 mmscfd.

DGC personnel have stated that the efficiency improvements were mainly the result of process and equipment changes throughout the plant. The operators have also diversified the plant's product slate, venturing into fertilizers, air separation products, chemicals and carbon sequestration.

Specific modifications and improvements made at the plant, and the implications of these experiences for future coal-to-natural gas facilities, are outlined in the following subsections.

Summary of Process Changes

The block flow diagrams on the next pages (Figures 2 and 3) illustrate some of the major changes to the original process of the GPSP. A majority of the changes from the original process resulted from management efforts to diversify marketable products and to meet environmental standards. The marketable products can be seen in the flow diagram as bold blue arrows or boxes. Although synthetic natural gas remains the main product, many other by-products have been created to supplement the gasification process. Other changes to the plant's process reflect safety, environmental, or efficiency improvements. Note that the figure shows only the major changes to the plant's configuration over the plant's 20 years of operation.

The major layout changes to the GPSP began with the addition of a startup flare early in the plant's operations, after the original startup incinerator didn't work. The liquid waste incinerator and Stretford sulfur recovery unit, which can be seen in the bottom right portions of the figure, were removed due to persistent operational problems. In 1990, the phenol purification unit was added downstream of the phenosolvan unit in order to purify phenol and other possible by-products. In 1991 the plant began recovering and selling krypton and xenon derived in the air separation unit. The next addition to the plant came in 1997 with the Flue Gas Desulfurization (FGD) unit, more commonly known as a scrubber. The FGD was added to the steam generation unit to scrub the sulfur dioxide (SO_2) from the boiler emissions. In 1997, an ammonia plant was also added. The ammonia plant creates fertilizer by using some of the process gas, which is diverted from the main process stream just after the Rectisol unit. A carbon dioxide (CO_2) pipeline and compressors were added in 2000 to sell CO_2 as a by-product for enhanced oil recovery (EOR), making the plant one of the first energy facilities anywhere to sequester carbon emissions. A Wet Electrostatic Precipitator (Wet ESP) was added in 2001 due to particle emissions from the FGD, which were causing a visible plume to be emitted from the plant's main stack.

Figure 2: Detailed Block Flow Diagram – Original Configuration

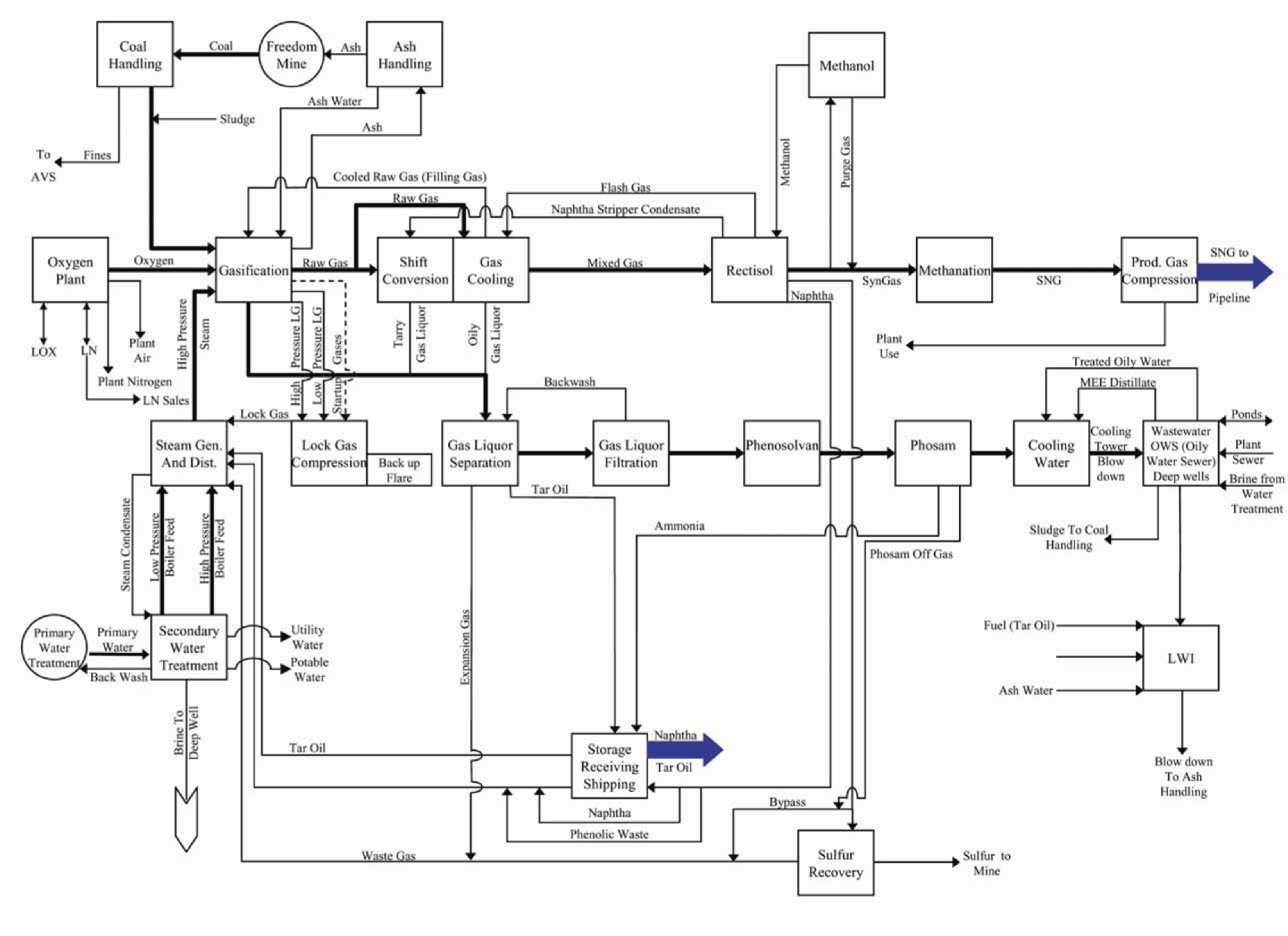
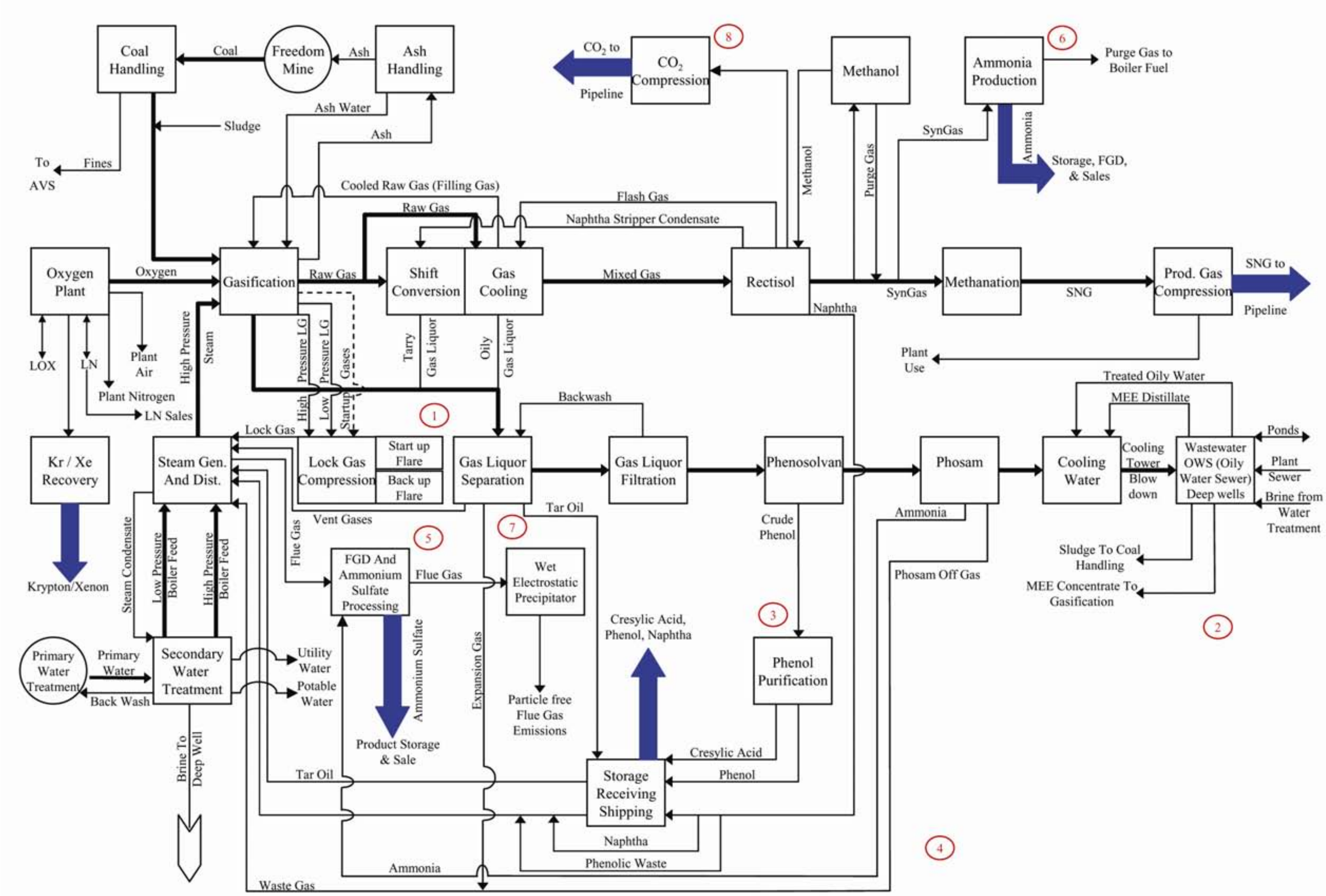


Figure 3: Detailed Block Flow Diagram – Current Configuration



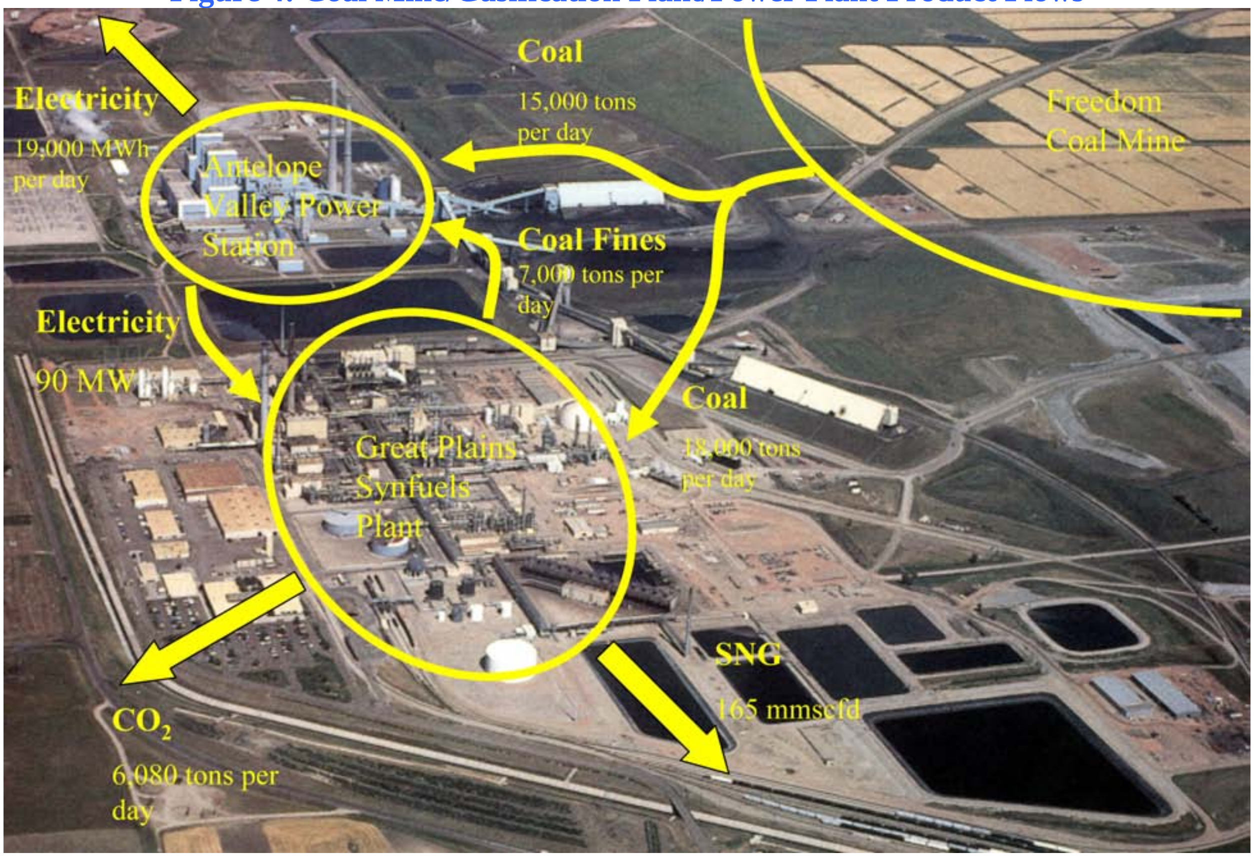
1) Addition of a Startup Flare in 1984
2) Removal of LWI in 1993
3) Phenol Purification unit added in 1990
4) Sulfur Recovery (Stretford) unit removed in 1994
5) Flue Gas Desulfurization unit added in 1997
6) Ammonia plant added in 1997
7) CO_2 Compression and Pipeline added in 2000
8) Wet Electrostatic Precipitator added in 2001

4. Plant Synergies

The GPSP is not an isolated facility in any sense of the word. The plant is a link in a lattice that forms an entire energy complex that must be joined with multiple other links to achieve its full potential. The requirements for economical operation of a coal gasification plant are not simply coal for feedstock and a customer for the SNG product.

Figure 4 below illustrates the synergistic relationship between the GPSP, the Antelope Valley Station (AVS) power plant, and the Freedom Mine in terms of primary products. The physical proximity of these three elements, combined with high-level cooperation between the three facilities, is an effective model for a future coal gasification plant or broader energy complex.

Figure 4: Coal Mine/Gasification Plant/Power Plant Product Flows



Picture courtesy of DGC

In discussions with GPSP managers and engineers, the idea that a coal gasification plant must, without exception, be co-located with a fluidized bed power plant at a mine mouth was repeated and emphasized. The need to minimize operational costs by being near to feedstocks and resources and sharing the expenses of some processes and resources make a co-located power plant a requirement for large scale coal gasification. The economic and operational benefits to this type of arrangement include:

1. a customer for coal fines and other coal that cannot be processed by the gasifiers
2. availability of inexpensive and abundant power
3. shared coal handling processes

4. shared water acquisition and transportation processes
5. shared ash disposal processes
6. shared stormwater management
7. shared emergency systems and procedures
8. shared train and vehicular transportation access
9. some shared skilled labor
10. shared local infrastructure

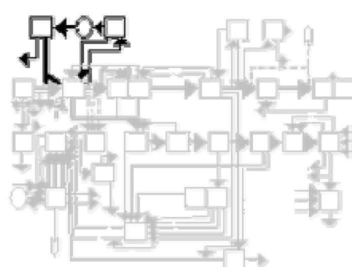
If a power plant and gasification plant are planned and constructed at the same time from the ground up as part of an "energy complex," the benefits can be increased. There may be benefits in the environmental permitting process, since the power and gasification plant combination could achieve lower combined emissions per energy unit produced. The GPSP is a good example of this, as the AVS has enabled the economic operation of the GPSP since its construction.

A future energy complex that includes a coal gasification plant can include any number of other energy processes. The GPSP now pipes CO_2 to a regional oil field where it is marketed for enhanced oil recovery. This activity achieves the triple benefit of enhanced revenue and sequestered carbon emissions for the gasification plant and enhanced oil production for the oil field. A gasification plant is most likely to be located near natural gas pipelines to transport the product to markets, and often those pipelines draw natural gas produced in oilfield operations.

5. Plant Processes

Each of the following sections provides background on certain aspects of the operation of the GPSP. Each section includes subsections describing what was originally intended to happen with the plant, what has been learned during the operation of the plant, and some of the implications to future coal-to-natural gas projects, as identified by DGC engineers and managers, technical reports, and studies.

5.1 Coal Crushing/Handling



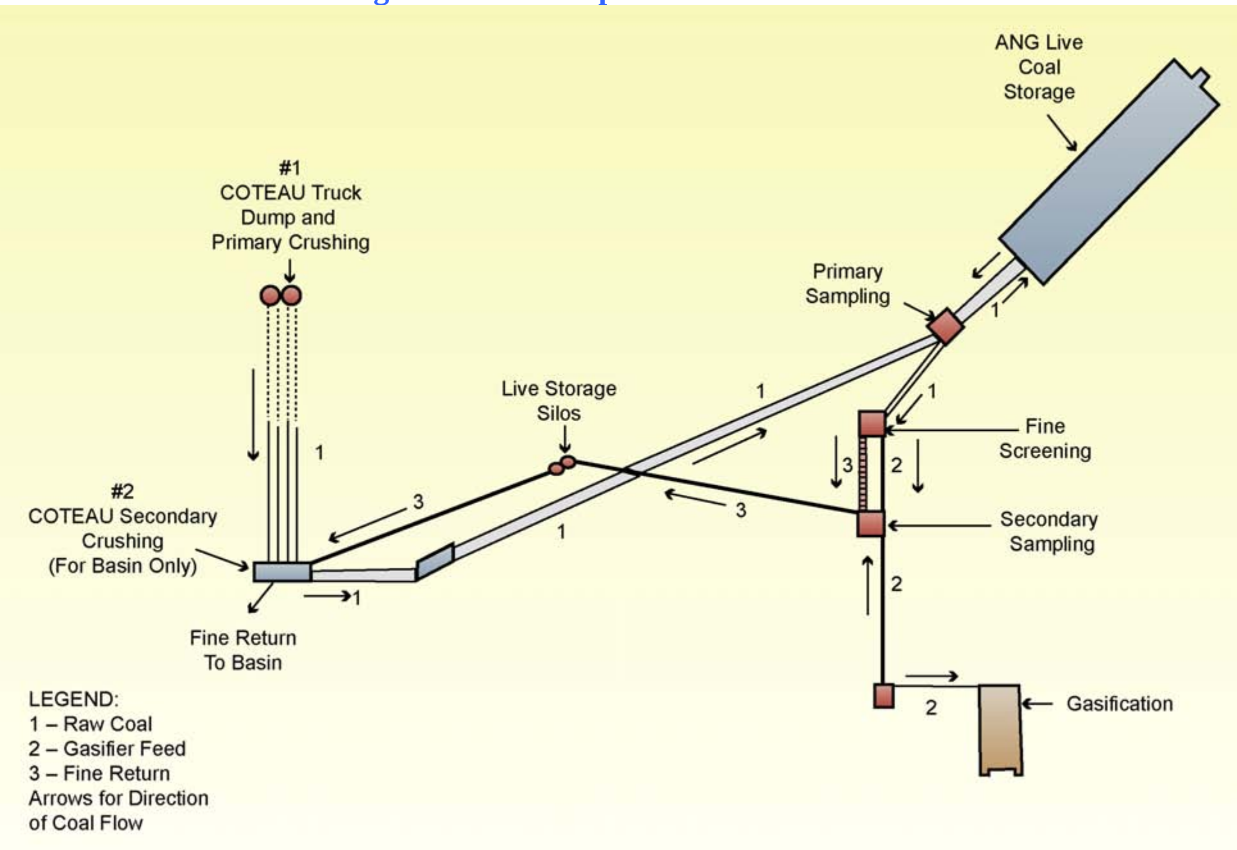
5.1.a The Plan

The original plant design focused on a system that fed coal sized between ¼ inch and 2 inches to the gasifiers while minimizing the amount of coal fines. The coal fines disrupt the gasification process because they tend to be carried upward with the gas towards the gas outlet line and cause a clogging of the downstream equipment. The Lurgi Mark IV gasifiers operate most efficiently when coal fine levels make up less than five percent of the feedstock. Most of the efforts for the design and implementation of the coal crushing and handling system were concentrated around the reduction of coal fines in order to increase the performance, productivity, and reliability of the gasifiers.

The equipment needed to create the correct feedstock included a system of screens and crushers. The two major components of the coal handling process were installed to eliminate the oversized coal through crushing and to separate out the coal fines through the use of screens. The process uses the Royer/Mogenson 1056 screens. Roll-type crushers manufactured by Pennsylvania

Crusher were installed to act as primary crushers. The secondary crushers were two-stage double-roll crushers.

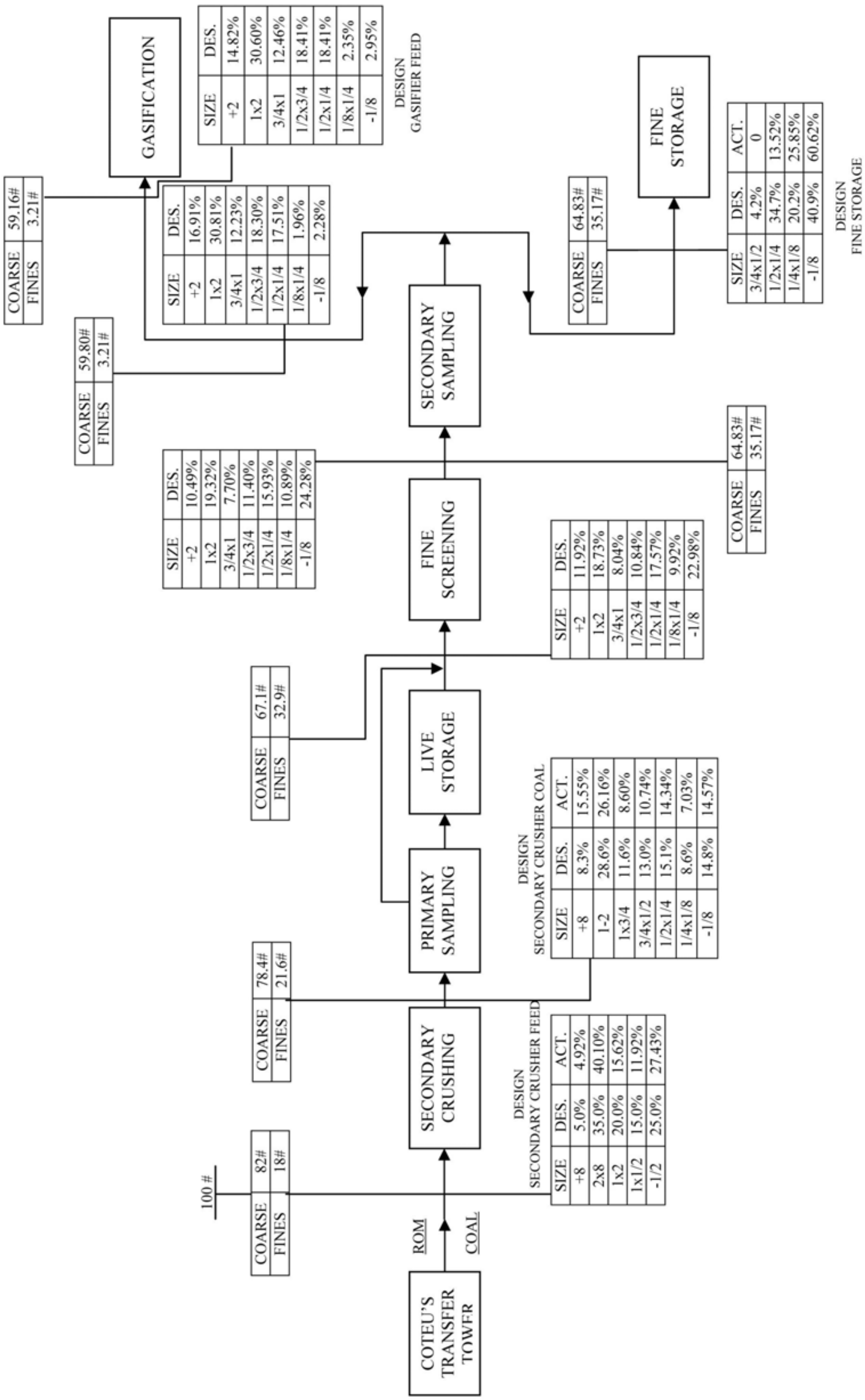
Figure 5: Coal Preparation Flow Scheme



5.1.b The Experience

Figure 6 on the following page, is a table taken from a 1988 Fluor Technologies report that details the differences between the results that the design of the coal handling system was expected to achieve and actually achieved.

Figure 6: Coal Preparation and Handling Design vs. Test Data



Source: Delaney, R.C., and Mako, P.F. Great Plains Coal Gasification Plant Technical Lessons Learned Report. Fluor Technology, Inc. November 1988

From the beginning of the plant's operation, reducing fines created by the storage, handling, and crushing of the lignite has been a necessary and difficult objective. The amount of fines in the feed has frequently exceeded the amount anticipated in the plant's design. Many adjustments have been made to improve the feed stock quality.

Better coordination between the adjacent Freedom Mine (operated by Coteau Mining Company) and the plant, as well as improved storage, crushing, and blending have resulted in better, more consistent feedstock for the gasification plant. Coteau plays a major role in the production of the quality of the feedstock and has adopted special mining practices to optimize feedstock quality. Coteau continuously takes core samples and develops a mine plan to satisfy the demands of the GPSP as well as their other customers

Plant operators have learned that the gasifiers can process larger size lignite chunks, and the feedstock now includes pieces up to 4 inches in size. A 4-inch piece of lignite is roughly the largest size the gasifier can accept; larger size coal can cause the coal lock inlet to clog. The ability of the gasifiers to accept larger than expected sizes of feedstock has helped to lower the amount of rejected coal fines.

This inverse relationship between the amount of larger coal and coal fines is a result of the crushers. Changes have been made to the crushing processes. The original primary crusher utilized a single roller against a fixed plate. This configuration often resulted in the formation of large slabs of coal. The primary and secondary crusher systems were replaced with a two-stage crusher manufactured by MMD which uses double rolls with offset teeth. The tooth setting on the crushers can be adjusted to produce a smaller feedstock, which in turn increases the amount of coal fines. A loose setting, on the other hand, will produce a larger feedstock with a smaller amount of fines.

The first stage produces 8 inch coal and the second stage reduces the size to 4 inches. There is no secondary crusher used — the discovery that the gasifiers could process larger pieces of coal than originally thought made the secondary crushers unnecessary, and the need to decrease the amount of fines made it undesireable.

After crushing, the second defenses against coal fines are the screens. At the GPSP, the screens reject approximately 42– 45 percent of the feedstock to reach an acceptable level of fines in the gasifiers. A number of different screening systems were tested to reduce the creation of fines, usually without noteworthy results. However, adding some additional screens has improved the quality of the feedstock, and the fines problem has been somewhat mitigated under BEPC's ownership because more separated fines are sold to the adjacent Antelope Valley Station (AVS) power plant. AVS is also owned and operated by BEPC.

The fines problem is aggravated by the wetness of the coal. When stored coal is mixed with wetter coal from the mine, the moisture causes the fines to adhere to larger pieces of coal, preventing the fines from being screened before entering the gasifiers. This is called "piggybacking" of fines. In addition, wet coal can clog the screens and reduce their ability to separate the fines. The screens must cleaned more frequently when the coal is moist.

Combining parts of the handling processes for GPSP and AVS has reduced some costs. Coteau and DGC personnel have found that fines can be reduced, and feedstock quality improved somewhat by:

1. careful monitoring of the wetness and storage life of the coal;

2. proper blending at the mine site and during storage, using multiple pits; and

3. minimizing the waiting period and the amount of excess handling of the feedstock.

All coal at GPSP is used within a week, and more often within days of arriving at the facility. Aside from the production of coal fines, the coal handling process at the GPSP has operated well.

5.1.c Implications for Future Project

Assumption: A future facility would also use gasifiers that are sensitive to coal fines.

- Fines will be generated, and co-locating with a facility such as a pulverized-coal power plant is a must in order to improve the economical use of the mined coal.

- Thorough analysis of the friability and other properties of the planned feedstock before selecting the coal handling system and equipment can aid in selecting the configuration and equipment that are optimal for creating the least amount of fines during the blending and handling process. GPSP operators stressed the importance of high-quality, conservatively designed coal handling equipment.

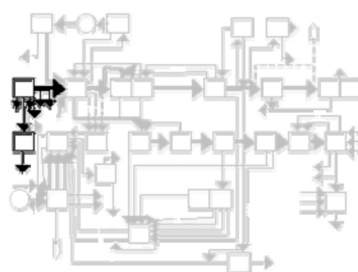
- Coal storage facilities and schedules that are designed to rotate feedstock so that coal that goes from the mine to the gasifier within three or four days while undergoing the least amount of handling will produce fewer fines.

- Constant communication between plant operators and mine operators' aids in creating optimal feedstock properties.

- If high coal moisture content were expected, a screening configuration in which the finer screens could be cleaned without interrupting the handling process would simplify the handling operations.

- The reliability of a co-located power plant or other outlet for the fines will affect the reliability of coal handling operations. However, a co-located power plant will need its own storage facility to keep coal properties optimal.

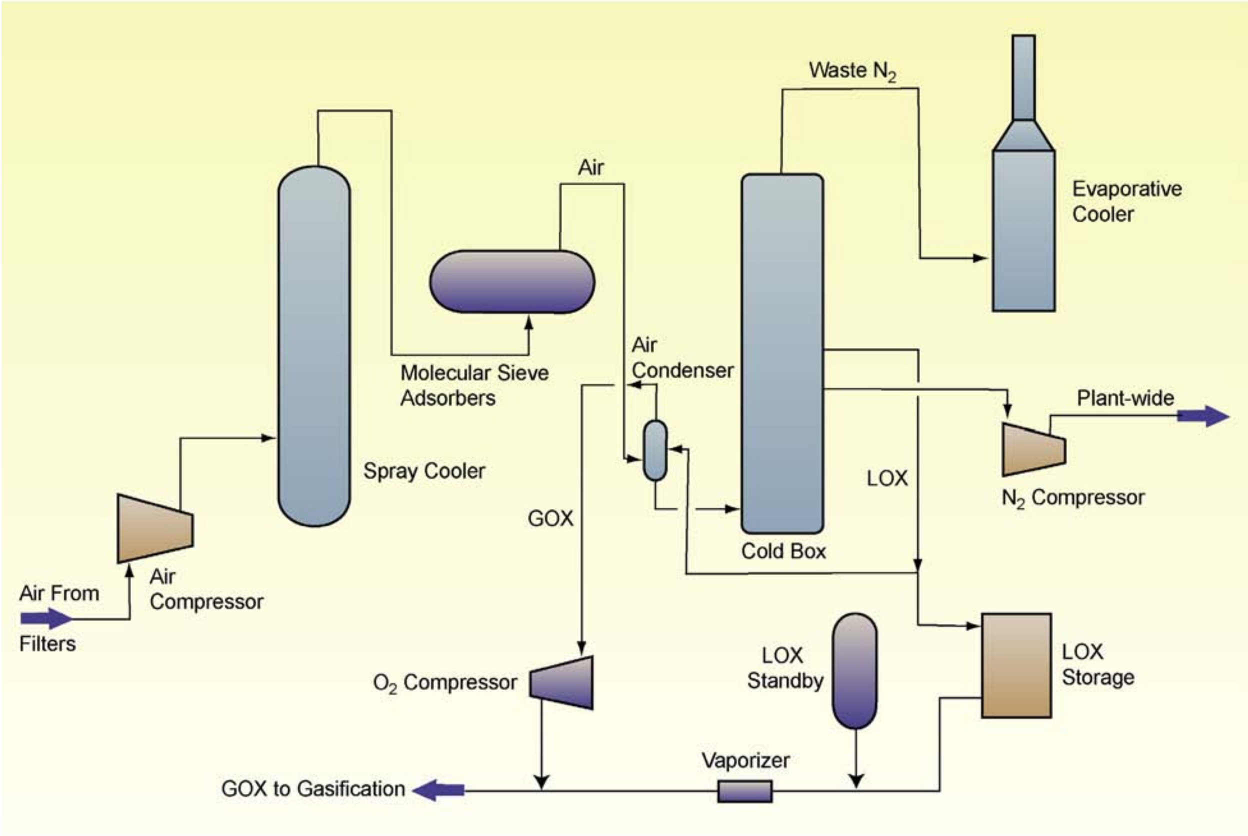
5.2 Oxygen Plant/Air Separation Unit



5.2.a The Plan

The Air Separation Unit (ASU) at GPSP is a molecular sieve-type, cryogenic separation unit rated for 3,100 tons per day of oxygen. The molecular sieve utilizes a shallow, horizontal bed. The reliability of this unit is extremely important, since any disruption in operation of the ASU results eventually in a discontinuation of gasifier operations. Stored liquid oxygen provides a temporary backup supply. Figure 7 shows a schematic of the oxygen plant.

Figure 7: Oxygen Plant



5.2.b The Experience

Oxygen Plant

The oxygen plant has generally performed well after a difficult initial startup period. Material failure of the waste nitrogen/steam heat exchanger and some instrument problems were fixed early in the process. Some DGC personnel noted that the molecular sieve used in the ASU might not be the best design for a future facility. The bed is prone to fluidization and CO_2 breakthrough. Design flaws resulted from scale-up issues, as the licensed process had not been proven at this scale. The design flaws were exacerbated by communication problems with the licensor.

Two of the ASU's four compressors are steam-driven, while the others use electric motors. This follows the general plant plan in which the mirror plant plan operates with one train on steam and the other on electricity. Some DGC personnel interviewed noted that the oxygen plant might be more effective using electric compressors rather than steam-driven compressors, because the plant as a whole runs a deficit of high-pressure steam and a surplus of low-pressure steam. However, the turbines provide efficient turndown.

5.2.c Implications for Future Projects

- Oxygen is a critical component of gasification; therefore the reliability of the oxygen supply will affect the reliability of the entire plant. A stored quantity of backup liquid oxygen is capable of running the gasifiers for up to several hours and providing a smooth transition during unit upsets.

- Careful consideration of the ASU compressors should be taken when analyzing the plant's steam balance. Using electric pumps may be preferable if sufficient high-pressure steam will not be reliably available.

- There was disagreement among plant engineers and managers about whether a parallel spare sieve unit would improve flexibility and reliability enough to warrant its cost. Similarly, a spare water chiller might provide additional reliability.

- Plant engineers recommended conservative sizing of the ASU for all expected ambient conditions, since a high ambient temperature is the primary rate-limiting factor for the unit.

5.3 Steam Generation

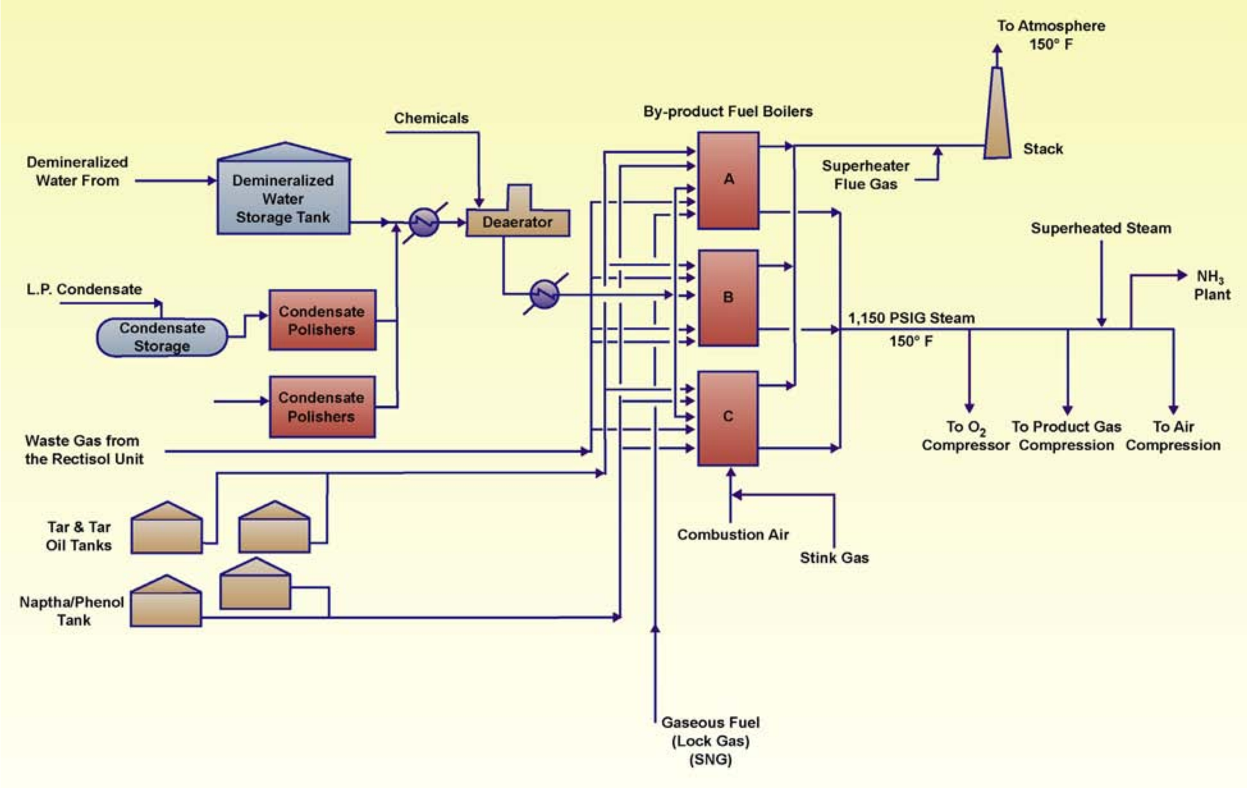
This section focuses on operations of the Riley Stoker boiler units themselves; a discussion of the emissions from the boilers and the systems installed to control those emissions is provided in later sections.

5.3.a The Plan

The plant uses eight different pressure levels of steam ranging from 1,250 psig to 25 psig. Three Riley Stoker Boilers, which produce 1,150 psig superheated steam, provide steam for the plant.

GPSP pioneered the use of steam boilers using six different fuels simultaneously. The fuels burned in the boilers include SNG, medium Btu lock gas, tar oil, a blend of phenols and naphtha, waste gases, and vent gasses. The design philosophy of the plant involved using these on-site sources to supply the entire steam demand of the plant, since there was no market for most of these commodities near the plant's location. Figure 8 on the next page diagrams the boilers system.

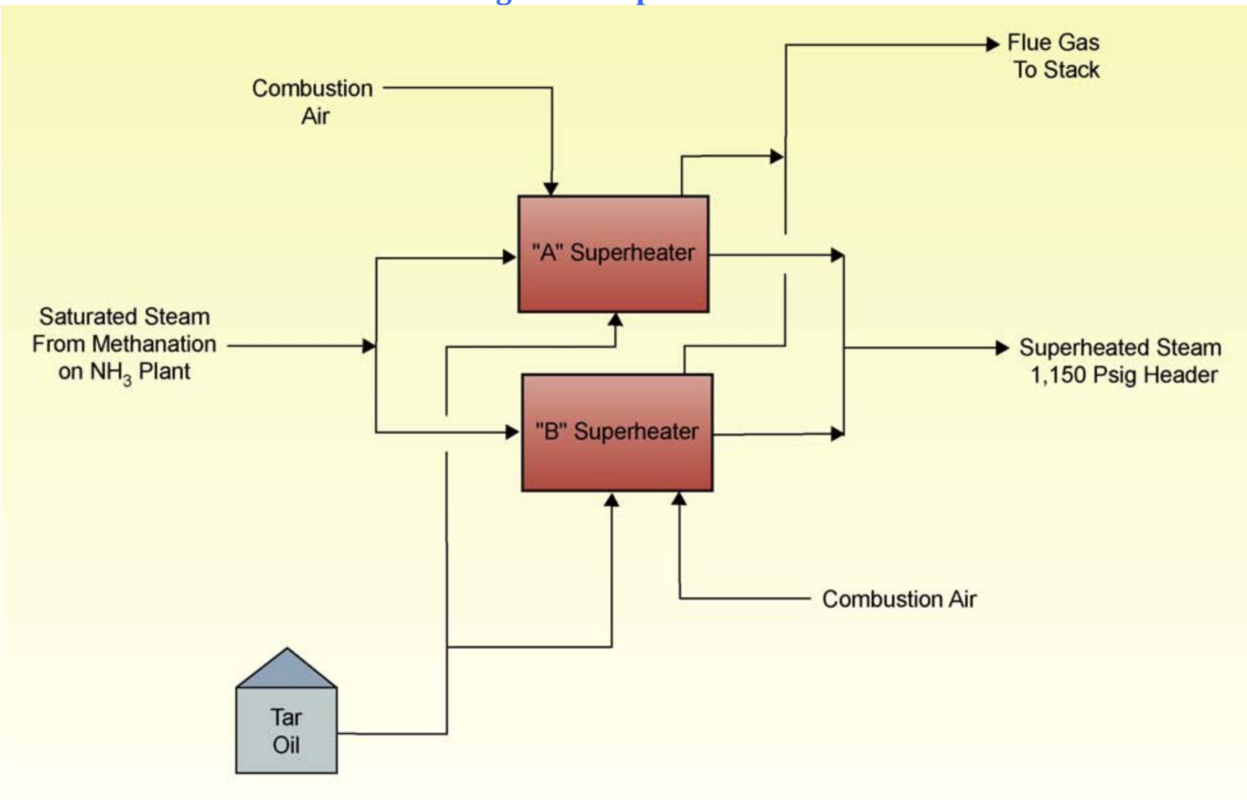
Figure 8: Riley Stoker Boilers & Multiple Fuel Sources



The cold lime-softened water from the adjacent AVS power plant is treated in the Secondary Water Treatment Plant. Here the water is first filtered and then treated with zeolite softeners. Part of the zeolite-softened water is used to provide boiler feedwater for the generation of low-pressure steam (100 psig and lower) and additional cooling water make up. The other part of the zeolite-softened water is treated in reverse osmosis units and mixed-bed demineralizers to produce high-quality demineralized water used for generation of high-pressure steam. Condensate is recovered, polished, and added to the high-pressure boiler system.

There are also two Superheaters, which take the 1,250 psig-saturated steam from the Methanation unit and superheat it for mixture with the 1,150 psig superheated steam. These Superheaters use tar oil as fuel. A simplified schematic of these superheaters can be seen in Figure 9.

Figure 9: Superheaters



5.3.b The Experience

The plant has required more steam than originally expected. The increase in steam demand is due to the fact that the plant has been able to operate at greater than expected rates of SNG production. The additions of the ammonia plant as well as the phenol purification unit have also increased the plant's overall steam consumption. The boilers have operated well, and since being re-rated in the late 1990s, have provided more than their original nameplate steam capacity. Integration with the steam generated by the exothermic reactions in the methanation unit has been smooth. However, it has been difficult to obtain an accurate overall steam balance in the plant because of a lack of steam flow instrumentation.

Two startup boilers were installed. They were originally intended to be decommissioned after plant operations normalized. However, it was recognized that, particularly during cold winter months, the startup boilers could be operated to increase the system's capacity.

From very early on, the plant's Stretford system for removing sulfur from the Rectisol acid gases experienced problems with clogging and ineffectiveness. In 1997, the layout was altered so that the acid gases, as well as vent gases from the gas liquor separation unit, were sent straight to the Riley Stoker Boilers and a FGD unit was installed to scrub the flue gas from the boilers.

Plant operators discovered that there is an upper limit to the amount of acid gases that can be fed to each of the boilers. When the waste gas volume exceeds the original design rates, carryover of liquid droplets occurs and causes deposits in lines and evaporator vessels. Therefore, a common practice at the plant during less than peak capacity steam generation is to run all three boilers at less than design rates, rather than shutting down one of the boilers.

5.3.c Implications for Future Projects

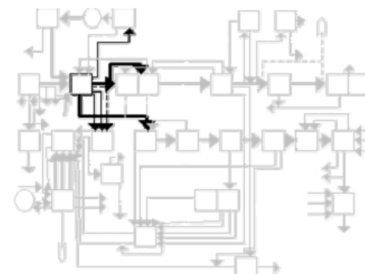
- Some DGC personnel promoted the idea of a spare boiler, a redundancy that the DGC plant does not have. According to one plant manager's estimate, more than half of the difference between maximum availability of the plant and actual availability is due to boiler downtime. However, other plant engineers disagreed.

- In the absence of a spare boiler, plant operators recommended a more conservative approach to boiler sizing.

- Installing a large amount of steam flow instrumentation in the plant can allow better tracking of steam consumption and energy management.

- Precise control over combustion air and the flow of all fuels into a multi-fuel boiler is highly desirable.

5.4 Gasification

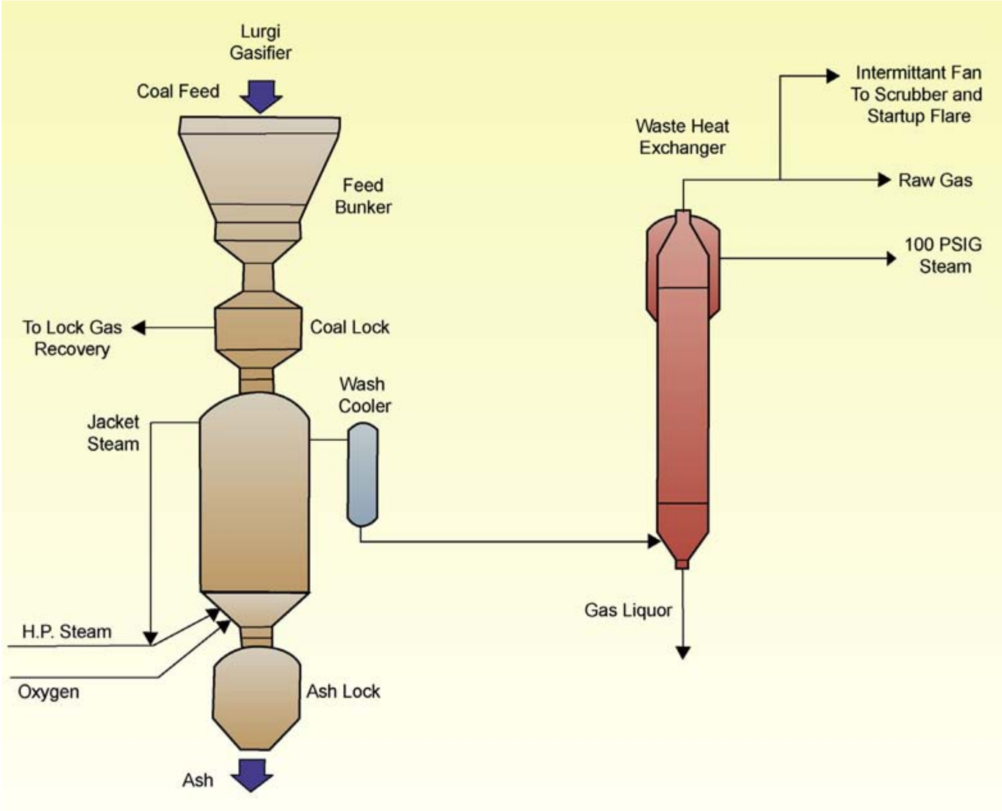


5.4.a The Plan

Production of synthetic natural gas and the other products begins with the gasifiers. The gasification unit consists of 14 Lurgi dry-bottom Mark IV gasifiers. The DGC plant was originally designed to run 12 gasifiers, with 2 available as reserve units. During normal operation, 18,000 tons per day of sized lignite coal are fed to the operating gasifiers. A simple drawing of the Lurgi gasifier can be seen on the next page in Figure 10.

Lignite is fed to each gasifier through a coal lock hopper mounted on top of the gasifier. The coal lock permits eight tons of coal to be withdrawn from the coalbunker, pressurized to gasifier pressure and discharged into the gasifier. During normal operation, the coal lock on each gasifier must be depressured, refilled with coal and repressured every eight minutes. Depressurization of the coal lock happens in two stages to produce two gas streams: high-pressure lock gas and low-pressure lock gas. High-pressure lock gas is sent to the lock gas recovery unit where it is scrubbed and collected. The low-pressure lock gas is sent to the same recovery unit where it is also scrubbed then recompressed and combined with the high-pressure lock gas. The combined lock gas stream is used as fuel in the plant's three Riley Stoker Boilers.

Figure 10: Lurgi Gasifier



Steam and oxygen enter the bottom of the gasifier through a rotating grate and are distributed by this grate. The air separation unit supplies oxygen for the gasification unit. Gaseous products and liberated volatile matter flow countercurrent to the coal feed and are removed in the upper part of the gasifier.

Picture courtesy of DGC

The installation of a Lurgi gasifier

The operating pressure of the gasifiers is approximately 460 psig. The reactions occurring in the gasifier produce extreme temperatures, reaching up to 2,300ºF in the combustion zone. Heat is recovered in the water-filled jacket of the gasifier by generating 460 psig steam, which is then mixed with 550 psig superheated steam and injected, along with oxygen, into the bottom of the gasifier.

The gaseous products and liberated volatile matter from each gasifier flow into a wash cooler where the stream is cooled to 400°F. This stream is further cooled to 380°F in a Waste Heat Steam Generating Exchanger. Part of the volatile matter is condensed to form dusty gas liquor (liquid condensed with suspended solids such as tar, oil, and coal fines). This gas liquor stream is sent to the gas liquor separation unit for further processing.

5.4.b The Experience

The Lurgi Mark IV fixed-bed gasifiers used at GPSP have proven to be more reliable and to have a higher capacity than was expected. Lurgi was chosen because it was the only proven technology at the time, which was very important to securing project financing. At SASOL in South Africa, the Lurgi system has also proven very reliable. No other gasifier is as robust and proven for lignite.

As noted in the coal handling section, operators have learned that the gasifiers can handle larger sizes of coal than originally thought, and they now process pieces of lignite as large as 4 inches.

Over the 20-year operation of the plant, improved understanding of the maintenance requirements of the gasifiers has resulted in improved availability of gasifiers — typically 13 or 14 are in use, rather than the 12 the plant was designed to operate at any one time.

During initial operation at the plant, some slight modifications to the gasifiers were made. A cylindrical metal sleeve, or “skirt,” was shortened in the upper part of the gasifiers to create a more uniform distribution of coal and to increase reaction time. Engineers also modified the grate and the oxygen distribution scheme inside the gasifier. The grate was modified in order to improve the distribution of oxygen and steam within the combustion zone. This modification also limited the oxygen flow to the outer walls in order to minimize heat-related damage to the outer walls.

Although the gasifiers have operated at or above specified performance levels, plant engineers and managers expressed concerns about other aspects of the Mark IV gasifiers, primarily related to the creation of multiple, poor-quality gas liquor streams. They state that the main disadvantages include the following:

- the quality of the liquid streams that are created due to the mild gasification temperatures;
- the need for lock hoppers (coal and ash);
- the wet ash handling;
- a much more complex waste water system;
- more difficulty in keeping the water cooling tower clean; and
- the operating costs, which according to some DGC personnel, may be as much as twice that of other technologies, because many of the extraneous costs to run the DGC plant are due to liquid processing.

Plant personnel suggested that there may be the potential to significantly reduce the number of processes and streams in a future plant by using a different gasification technology.

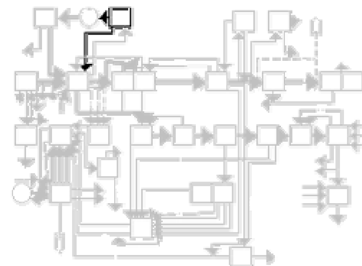
5.4.c Implications for Future Projects

- DGC engineers and managers have been nearly unanimous in asserting that a future coal-to-natural gas facility would use a different gasification technology. Using a technology that did not create as more pure liquid by-products could mean no gas liquor separation, no wastewater treatment, no phenosolvan, simpler ash handling, and probably a cleaner cooling tower.

- In addition, some DGC personnel suggested that a different gasifier system would mean much less labor for maintenance of the plant as a whole — possibly half as much as the current plant uses. They also recommended designing around a smaller number of larger gasifiers for reduced maintenance costs; however, this sentiment was not unanimous.

- The new gasifier technology most commonly mentioned by DGC personnel was a transport (TRIG) gasifier currently under development by a group that includes Southern Company and Kellog Brown and Root (KBR). The TRIG gasifier will be scaled up as part of a recently announced IGCC project in Florida. If the technology proves as good as advertised, DGC managers promoted the idea of using the TRIG reactor along with an char combustor to capture the 1,500 Btu/lb of energy left in the ash. They noted that the TRIG reactor would require more shift conversion capacity.

5.5 Ash Handling



5.5.a The Plan

Ash from the gasification process moves to the bottom of the gasifier and is removed through the ash lock. Ash from each of the ash lock hoppers is discharged to a sluiceway, where circulating water hydraulically transports the ash to the ash handling area. There the ash is dewatered in decanter vessels and loaded into haul trucks for disposal at an approved landfill.

5.5.b The Experience

The ash handling system at GPSP has been problematic. Most of the problems stem from inadequate understanding of the fluctuation of ash properties before and during the plant's design. Though ash-handling techniques were tested at SASOL, more thorough testing could have revealed some problems with the system design.

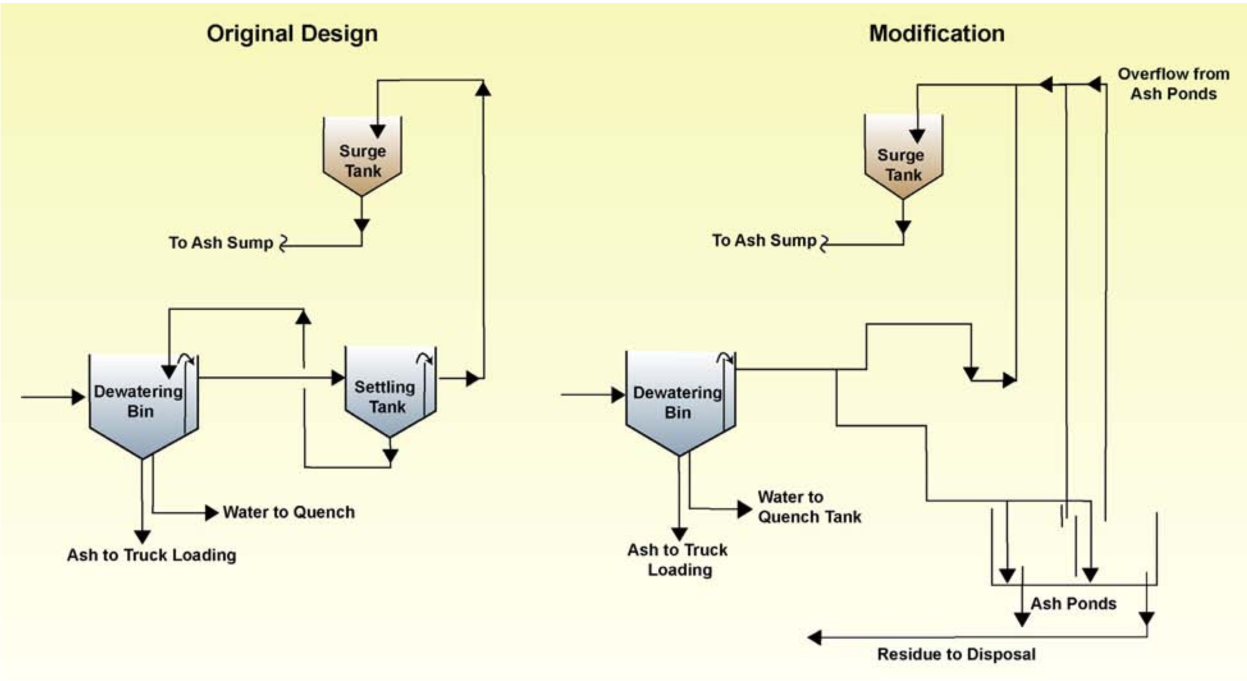
The sluiceways used to transport the ash have experienced cementation and buildup that led to reduced performance or clogging. The ash particles settled more quickly than anticipated, cementing to each other and constricting flow in the sluiceways. The constrictions had to be removed from the sluiceways mechanically. Adding rock salt to the slurry promotes the formation of an ionized layer around the particles and prevents them from coagulating, but is very costly. This practice was discontinued.

The abrasive properties of the ash slurry also led to degradation of the sluiceways. Originally lined with firebrick material, plant operators found that a basalt rock lining worked best in the sluiceways. The connecting pipes, which were originally cast iron, have lasted much longer since being changed to carbon steel with a basalt rock lining.

During initial plant operations, the dewatering bins frequently clogged due to overfilling, infrequent or slow emptying of the bins, or failure of the bin vibrators. A high-pressure water spray station, new vibrators, and a more strict operating procedure focused on minimizing residence time have helped reduce this problem.

In the original plant design, ash was to be disposed into a mine disposal site. However, coal fines from the coal handling area, dust collectors, and fine ash from the settling tank hindered the ability of the bulk ash to be separated from the water. Therefore, fine ash had to be routed to two parallel ash ponds. In the ponds, the overflow is taken to the surge tank and subsequently back to the ash sump, while the settled fine ash is routinely scooped out and transported by truck to the mine disposal site.

Figure 11: Ash Handling



5.5.c Implications for Future Projects

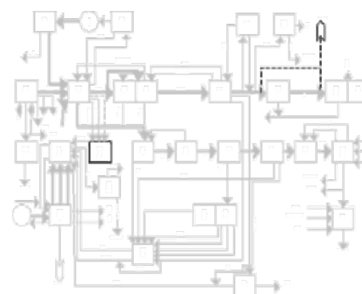
Assumption: The items identified below are focused on issues relating to ash handling for a dry-bottom gasifier. In addition, some of the ash-handling issues faced at the GPSP may be feedstock-specific and relevant only to gasification of North Dakota lignite.

- If the ash discharge from the gasifiers is at an elevated height compared to the disposal site/departure point, sluiceways for ash handling can rely on gravity flow rather than mechanical pumping, and will be less susceptible to changes in ash properties.
- Ash handling designs, which plan for variations in ash particle sizes related to variations in gasifier/feedstock performance, will be more robust.
- Maintaining a minimum velocity of slurried ash will prevent the settling of ash particles. Dumping ash from the ash locks in a consistent, uniform pattern enables an even and constant flow in the sluiceways.
- High-pressure water sprays may be required to keep the ash from cementing in any stagnant areas.

- If the steam concentration in the gasifier feed gets too high, the resulting ash is generally smaller and more porous. As these ash particles settle at a slower rate, cementation occurs more quickly. Therefore, preventing excessive steam ratios in gasifiers will reduce cementation in the ash handling system.

- Careful consideration during the design phase to ash slurry properties, such as abrasiveness and particle size, will lead to more efficient and longer-lasting sluiceways and pipes. In the case of the combination of dry-bottom gasifiers and North Dakota lignite feedstock, basalt rock has been the most effective lining material.

Strict operating procedures for emptying the dewatering bins can reduce incidents of overfilling and plugging.

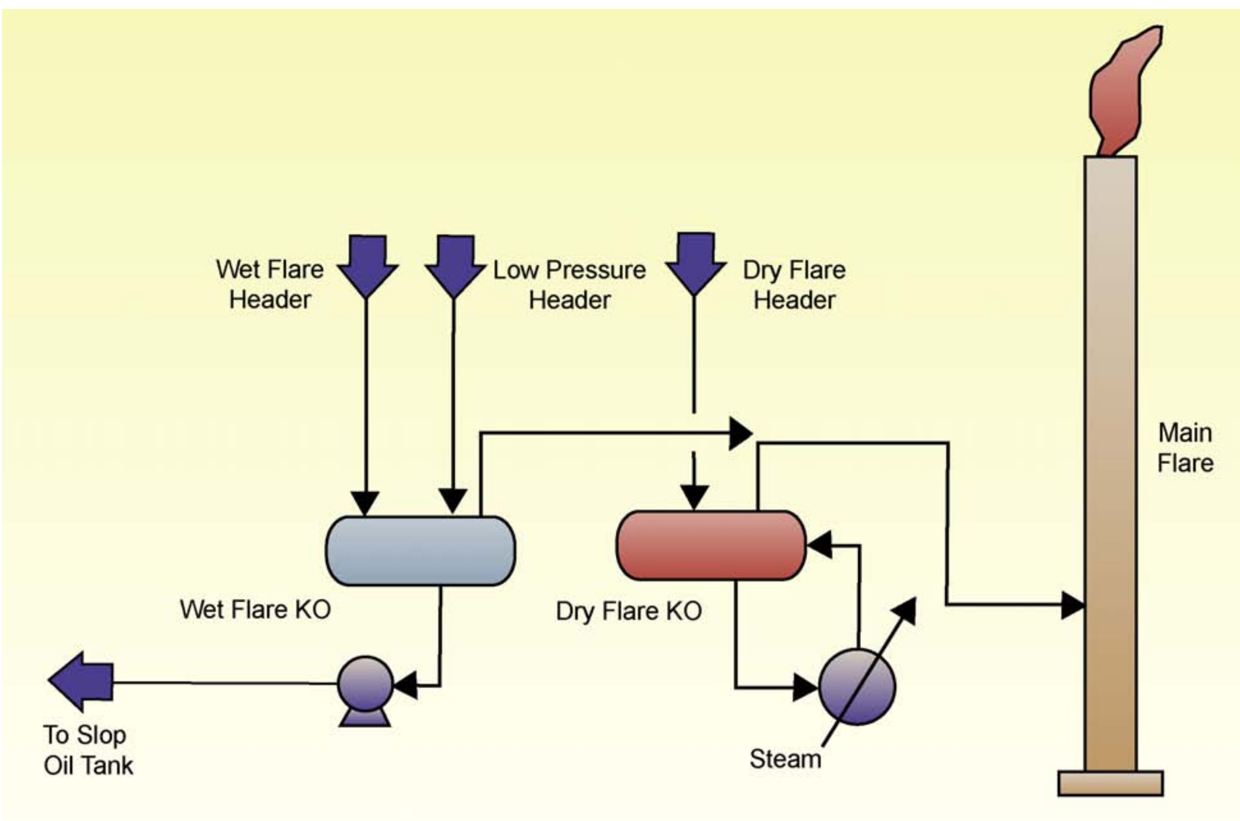


5.6 Flare System

5.6.a The Plan

The main plant Flare System, located at the south end of the plant, is integrated with the main relief system for the plant. The main flare system, on the south end, is shown in Figure 12. The startup flare and backup flare systems, located at the north end of the plant, served to dispose of off-spec gases during startup and shutdown of the gasifier, excess lock gas, and excess expansion gas from gas liquor separation.

Figure 12: Main Flare System



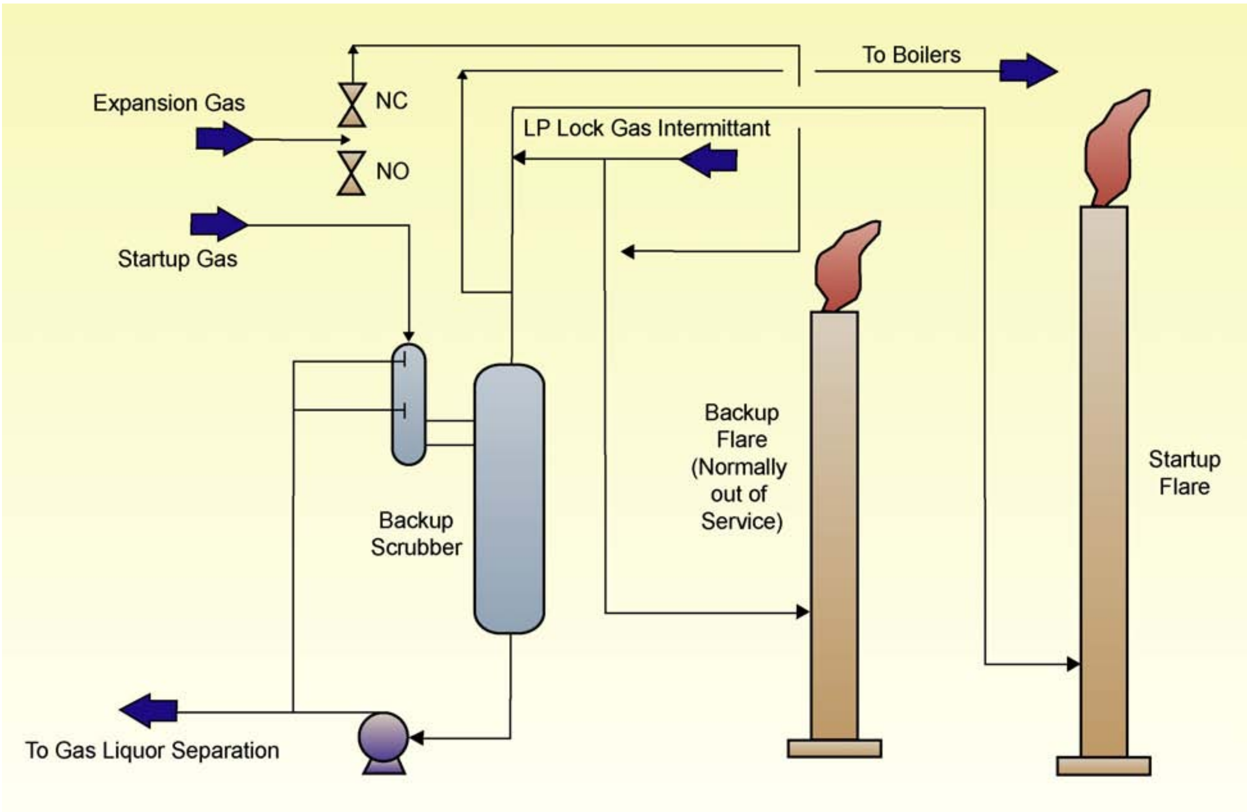
In the original plant design, the startup incinerator was expected to burn the off-spec gases during startup periods, and the backup flare provided a mechanism for disposing of waste streams during startups or upsets.

5.6.b The Experience

The startup incinerator did not have great enough surge capacity, and the backup flare was designed to handle streams from only two and a half gasifiers. When the incinerator tripped, overflow to the flare overwhelmed it, causing a venting of uncombusted waste gases and severe odor problems, as well as blown liquid seals in the expansion vessel of the gas liquor separation unit. This in turn overwhelmed the unit's vent system.

A new startup flare system, sized to handle the worst possible flare start-up load, was installed to replace the incinerator. More recently the backup flare has been taken off line and maintained as a standby for the startup flare. The system is also able to handle the expansion gas relieved from the gas liquor separation unit. Later a system was installed to recover the expansion gases from the gas liquor separation unit and feed it into the boilers. This has proven to be a valuable fuel stream for the boilers. A schematic of the north end flare system, the backup and startup flares is shown in Figure 13.

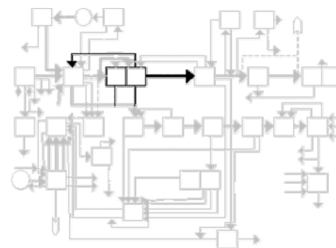
Figure 13: Startup/Backup Flare System



5.6.c Implications for Future Projects

- Sizing the startup incinerator to handle gases from multiple gasifier startups can prevent the flare system from being overwhelmed.

- Careful consideration should be given to the results of pressure transients in the gas liquor separation unit.



5.7 Gas Cooling/Shift Conversion

5.7.a The Plan

The cooled raw gas from the waste heat generating exchangers is split into two streams. One stream enters the raw gas cooling unit where the raw gas is cooled via waste heat exchangers and cooling water exchangers to 95°F. The cooling of the raw gas in this unit also causes additional gas liquor, known as tarry gas liquor, to condense. Part of the tarry gas liquor is used in each gasifier's wash coolers, with the remainder sent to the gas liquor separation unit. A portion of the cooled raw gas is recycled to the gasifiers for repressurization of the coal lock hoppers.

The remainder of the raw gas (about one-third of the total raw gas) is sent to the shift conversion unit. The raw gas produced in the gasifier has a hydrogen to carbon monoxide ratio that is less than optimum for operation of the methanation unit. In the shift conversion unit, carbon monoxide and water are reacted to form hydrogen and CO_2. This reaction takes place in three reactors that contain a cobalt-molybdenum catalyst. The shift conversion unit consists of two 50 percent capacity trains (there are six total reactors).

Gas from the shift conversion unit, referred to as shifted gas, is sent to the shifted gas cooling unit. There the shifted gas is cooled to 95°F and recompressed. The cooled and recompressed shifted gas is combined with the cooled raw gas from the raw gas-cooling unit. Cooling of the shifted gas in this unit condenses gas liquor, known as oily gas liquor, which is sent to the gas liquor separation unit.

5.7.b The Experience

The shift conversion unit has operated without major problems. The raw gas from the gasifiers has had a greater than expected hydrogen to carbon dioxide ratio, so the shift conversion unit has not needed to run at its full design capacity.

The pre-reactor has been very effective in removing any tar or fine ash that was not precipitated in the cooling train, resulting in better than expected catalyst life. However, the exchangers on the cooling train have experienced an accumulation of tar and similar impurities, both on the gas side and the cooling waterside, which can be controlled and cleaned with careful regular maintenance.

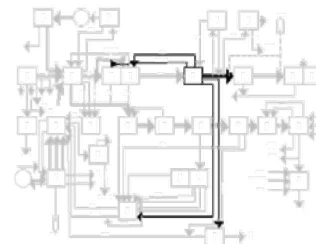
Problems with fouling on the water side of the heat exchangers in the gas cooling units caused a series of problems. The fouling occurred primarily because of the high organic content in the cooling water, which is discussed in the water treatment section. The fouling caused a loss of thermal efficiency in the exchangers. A process to clean the exchangers while online was implemented. The cleaning has helped alleviate the fouling.

A 1988 report by Fluor Technologies recommended installing a third parallel train in the gas cooling area. This project was never initiated.

5.7.c Implications for Future Projects

- Installing an extra parallel train in the gas cooling area will allow for simpler cleaning of heat exchangers without shutting down or limiting plant output.

5.8 Rectisol Unit



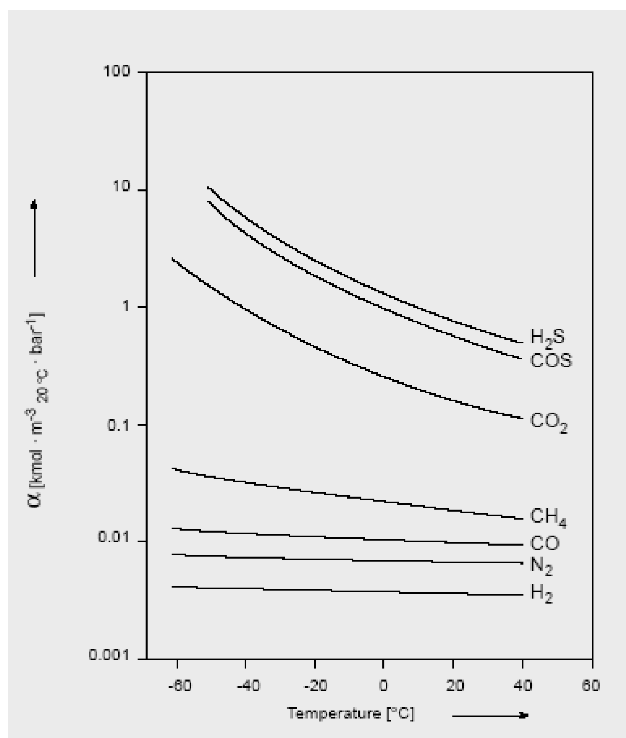
5.8.a The Plan

The Rectisol process is used in order to remove impurities from the synthetic natural gas. The impurities that are removed from the gas in this process include CO_2, naphtha, and varying sulfur compounds. These impurities are removed through a series of washes and pressure changes. The basic idea behind the removal process is that the solubility of each impurity varies in a methanol wash. The graph to the right, obtained from the Lurgi Web site, shows the variation in absorption coefficient, α, for each substance. The actual process of absorbing each component and subsequently cleaning methanol is a very complex and energy intensive process.

The combined gas stream of cooled raw gas and cooled shifted gas enters the Rectisol Unit. There the feed gas is first cooled, then contacted in stages in an absorber with methanol that has been cooled to a low temperature by an ammonia refrigeration system. The acid gases, including sulfur compounds and higher hydrocarbons, are removed by physical absorption into the methanol. The resulting clean gas stream contains approximately 20 ppb of total sulfur compounds.

The methanol from the Rectisol absorber, loaded with naphtha, sulfur compounds, and CO_2; is flash stripped and recovered for recirculation to the absorber. To replace methanol lost in the process, a small methanol synthesis unit is fed clean gas from the Rectisol unit to synthesize makeup methanol from hydrogen and CO.

Figure 14: Absorption Coefficients

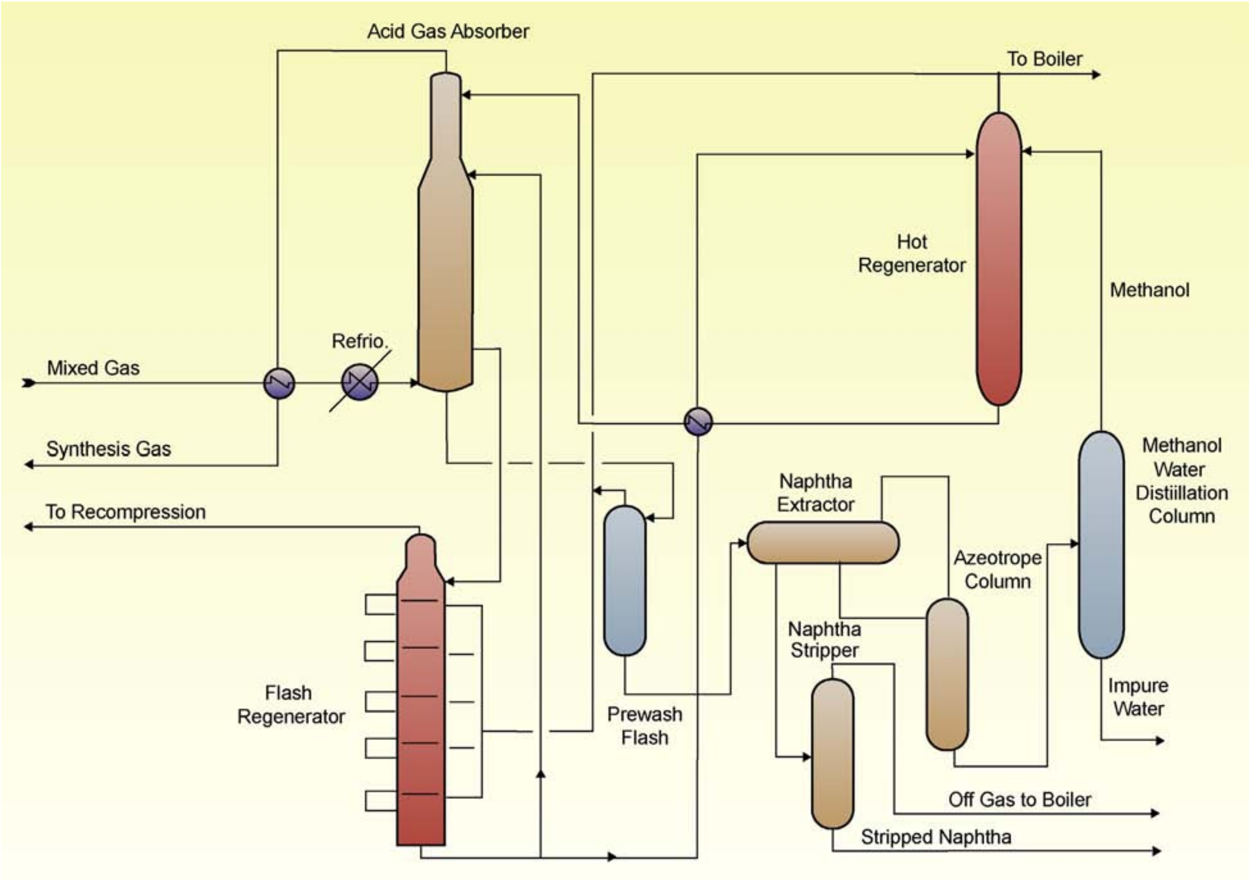


Recovered naphtha from the Rectisol Unit is cleaned and either sold as a by-product or burned as a fuel in the plant's Riley Stoker boilers. The sulfur compounds and CO_2-rich gas stream, known as waste gas, is used as a low-Btu fuel in the plant's three Riley Stoker boilers. A portion of this waste gas stream is sold for use in the tertiary recovery of crude oil. Figure 15 on the next page illustrates the different parts of the Rectisol unit.

Picture courtesy of DGC

Rectisol Unit upgrades during the Black Plant that resulted in production increases

Figure 15: Rectisol Unit



5.8.b The Experience

The Rectisol Unit is one of the most complicated units at GPSP, is the largest utility consumer in the plant, and has been a constraint on production at the plant. Several DGC personnel identified this area as the most significant "bottleneck" in SNG production going forward.

In early operation of the plant, excessive fouling and tube rupture was observed in the heat exchangers that cool the raw gas to the prewash section of the absorber. It was determined that inadequate de-icing resulted in poor heat transfer and fouling from ice. A new methanol spray system was installed, as well as a centrifugal pump, which delivered more consistent pressure for the spray system, and the fouling and tube rupture ceased.

The acid gas absorbed in the Rectisol Unit is released from the circulating methanol solvent in a series of six pressure and vacuum flashes. The cold flash gas is then heated by exchange with liquid ammonia refrigerant. However, it was discovered that this heat exchange process was getting partially blocked, and the acid gas temperature was significantly colder than designed. This in turn affected the acid gas compressor. A baffle in the heat exchanger was redesigned, and the control algorithm for the compressor was altered to recycle warmer gas when necessary.

Cavitation in the prewash and absorber pump prevented the Rectisol unit from delivering the designed flows of cold methanol. An alteration in the layout prevented the entrained vapor that led to cavitation.

The methanol water column experienced a number of problems. The methanol water column is important because it serves both trains and affects most phases of the Rectisol process. Excessive foaming was observed in the middle and upper trays, and plugging and fouling in the lower trays. Flow was constricted such that the tower had to be shut down for cleaning every 6 to 10 months at enormous cost to production.

North Dakota lignite is rich in oxygen and sulfur. When gasified at relatively low temperatures, oxygenated and sulfur-containing hydrocarbons are produced. These species detrimentally affect water column performance. The naphtha extractor is affected by the presence of oxygenated hydrocarbons. Measures to correct the problem included purging a stream from the azeotrope column, lowering the temperature in the extractor to decrease the solubility of the naphtha and other hydrocarbons, and injecting caustic (NaOH) into the extractor. In addition, an anti-foaming agent was added to the methanol water column to reduce foaming.

Efficient Rectisol unit sulfur removal is vital to increased life of the methanation catalyst. During initial operations, a higher than expected amount of sulfur was carried through to the Rectisol syngas. Research eventually determined that methanol from the hot regenerator contained a small amount of mercaptans. The hot regenerator was modified to allow nitrogen stripping in the column along with a small amount of air to oxidize some of the mercaptans. This alteration dramatically reduced the methanol contamination, and increased the efficiency of the sulfur removal.

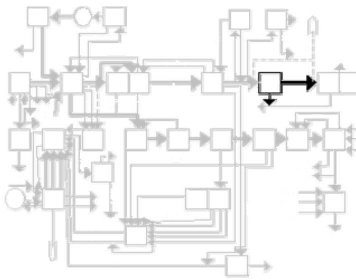
During the plant's planned outage in June 2004, new Rectisol tower trays were installed. The new trays have enabled a significant increase in gas production and improved sulfur removal efficiency.

5.8.c Implications for Future Projects

Assumption: A future plant would use a Rectisol process for sulfur removal.

- A conservative sizing of the ammonia and flash gas systems is required to optimize heat transfer.
- The acid gas cleanup unit will cause fewer problems when designed to have the flexibility to handle unexpected hydrocarbons and conditions, especially the equipment that serves both or all of the plant's process trains.
- PH control improves the extractor operation and diminishes entrainment of naphtha. Feeding the methanol/water column with a cleaned methanol/water mixture results in less corrosion, greater throughput, and purer products.
- Simple nitrogen stripping in the hot regenerator column is an effective way to improve the sulfur removal efficiency of this column.

5.9 Methanation



5.9.a The Plan

The clean, sulfur-free raw synthesis gas from the Rectisol unit enters the methanation unit where it is converted to methane-rich, high-Btu gas. The main reaction of CO and hydrogen to methane and water takes place in down-flow methanation reactors, which use a pelleted, reduced nickel-type catalyst. CO_2 is also reacted with hydrogen to form methane, but this reaction is not as complete. The chemical equations for the two reactions are as follow:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta H = -113.6 \text{ kJ/mol}$$

$$CO + 3H_2 \rightarrow CH_4 + H_2O \qquad \Delta H = -210 \text{ kJ/mol}$$

These reactions are highly exothermic and are used to produce 1,250 psig-saturated steam. The gas leaving the synthesis loop in the methanation unit is passed through a "cleanup" reactor in order to completely convert any remaining CO and some CO_2 to methane.

5.9.b The Experience

The methanation unit has worked very well, according to DGC personnel, as long as the sulfur is effectively removed from the syngas that enters the unit. Plant managers report no significant problems with its operation, and process performance has been described as “above expectations.”

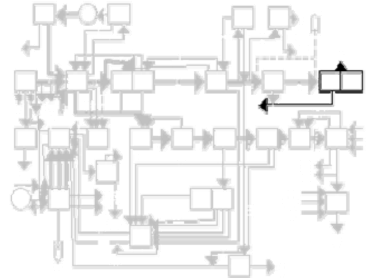
The only significant change made to the methanation unit since operations began is the addition of a bypass loop for the final reactor. This was done so that when production rates in the overall plant are decreased for reasons outside the methanation process, both sides of the methanation unit could be kept on-stream rather than having one side shut down.

Methanation catalyst performance is dependent on Rectisol unit performance. The sulfur content in the Rectisol syngas needs to be kept below a certain level (20 ppb for the GPSP) to extend the life of the catalyst.

5.9.c Implications for Future Projects

- Design the methanation unit such that it can handle downturns in plant production in order to give greater process flexibility.
- Develop reliable methods for sampling and analyzing syngas.

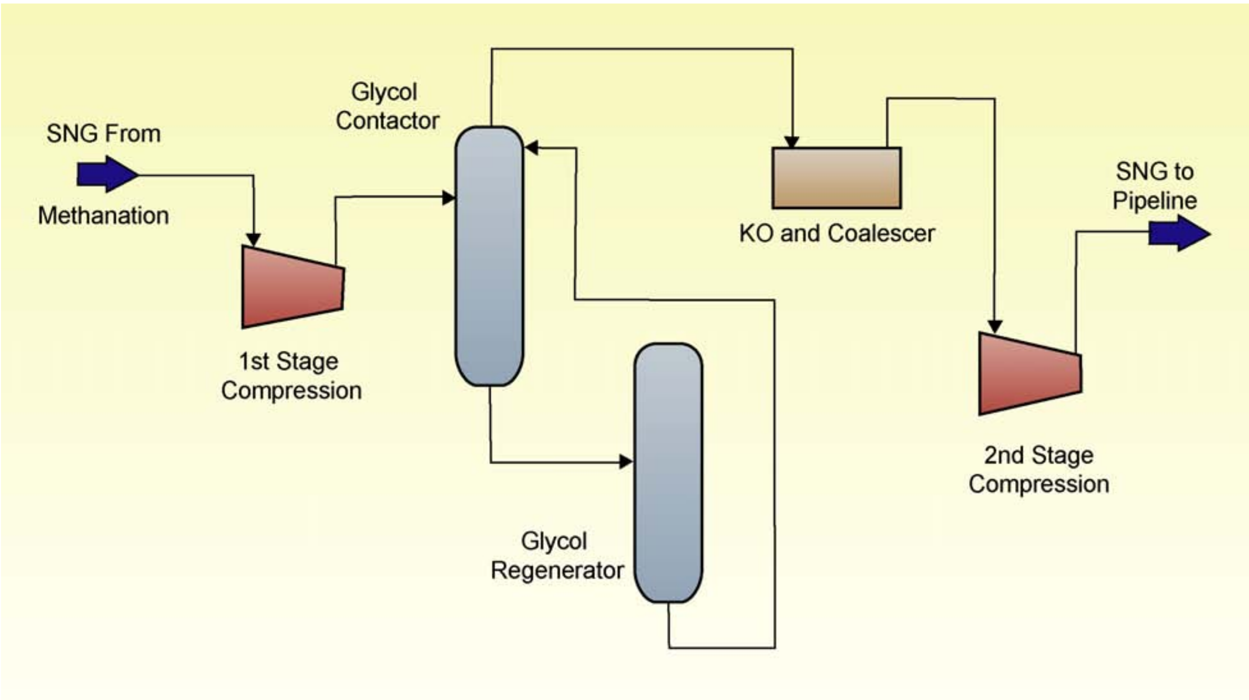
5.10 Compression



5.10.a The Plan

The SNG product is sent to the product gas compression unit where it is dehydrated and compressed to a pressure necessary to transport it by pipeline to market. Following compression, the SNG meets pipeline quality standards and is then commingled with natural gas in an interstate pipeline system at a connection located approximately 34 miles from the plant. A schematic of the compression system can be seen below in Figure 16.

Figure 16: Product Gas Compression



5.10.b The Experience

After some modifications, DGC engineers and managers have praised the current compression process used at the GPSP as being very good.

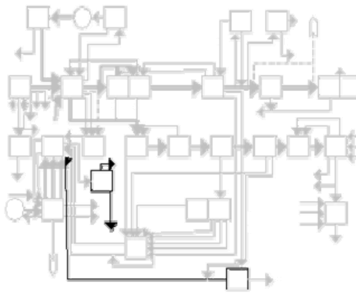
The original turbines exhibited poor efficiency and reliability, and at maximum speed only marginally met the original throughput of the gasification process. They had no capacity for plant capacity expansion. Plant operators upgraded the product turbines with larger, more efficient models that were capable of sustaining the maximum allowable speed of the compressor. This change provided the opportunity to debottleneck the plant by increasing the operating pressure. Since that point, the compressors have performed above expectations and plant output has been increased. DGC cited the installation of the upgraded turbines as one of the biggest contributors to increased SNG production during the operational history of the plant.

Some problems with the drying system and glycol fouling were experienced. The original dryer skids were too small for the water loading.

5.10.c Implications for Future Projects

- Effective product compression can contribute greatly to increased plant performance.
- Conservative sizing of drying equipment can prevent fouling.

5.11 Sulfur Recovery/Stretford Unit



5.11.a The Plan

In the initial layout of the plant, a "Stretford" sulfur recovery unit, utilizing liquid reduction/oxidation technology, was used to treat the waste gas from the Rectisol and ammonia recovery units to remove hydrogen sulfide (H_2S). The Stretford unit converted the H_2S into elemental sulfur. The scrubbed acid gases were then combined and sent to the plant's Riley Stoker boilers for use as fuel.

5.11.b The Experience

In operation, the Stretford unit never worked well. Plugging problems were pervasive. GPSP operators embarked on an extensive series of tests and evaluations, which eventually determined that the problems were unfixable, and that for high CO_2 waste streams containing high levels of mercaptans and other organics, Stretford process chemistry could not economically achieve adequate H_2S removal efficiencies.

Picture courtesy of DGC

Ammonium Sulfate Production and Storage

As a result, the decision was made to shift to a different liquid redox process. The Sulfolin process was selected because capital costs of the change were less than other alternatives. However, the Sulfolin unit failed to provide measurably better results.

Eventually the idea of a post-Rectisol H_2S recovery process was scrapped altogether. The acid gases from the Rectisol unit were sent directly to the Riley Stoker boilers. To meet environmental standards, a FGD unit was added to the boiler system to scrub SO_2 emissions.

The scrubbing section of the FGD unit is set up much like a conventional wet limestone forced oxidation unit with the exception that the FGD unit at the plant uses ammonia to scrub the SO_2 rather than limestone. Scrubbing the SO_2 with ammonia produces ammonium sulfate. The ammonium sulfate crystals produced in the scrubbing section of the FGD unit are sent to the dewatering and compaction section where ammonium sulfate granules are produced.

Traces of ammonium sulfate in the scrubbed flue gas created a visible plume emanating from the plant's main stack. A wet electrostatic precipitator (Wet ESP) was added to the FGD system to eliminate fertilizer particle emissions. The Wet ESP removes the particles using an electrical charge to attract the microscopic particles from the stack gases, causing them to attach to a metal plate. Water rinses the particles from the plate, and the particles are then removed for disposal.

5.11.c Implications for Future Projects

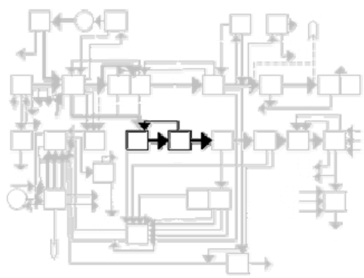
- Managers and engineers were nearly unanimous in suggesting that future plants would not be designed to use the Stretford process, since it never worked at the DGC plant. However, it was mentioned that some new Stretford process units have been demonstrated, most notably in China, which might not have the same problems.

- Among the persons interviewed, a conventional limestone FGD system or an improved back end of the scrubbing process was recommended for a plant like the GPSP. They pointed out that even marketing the ammonium sulfate does not cover the cost of the desulferization process. They noted that in a better-designed plant, the ammonium sulfate system could make better economic sense.

- It was also recommended that a FGD process designed to operate in two trains would provide greater reliability.

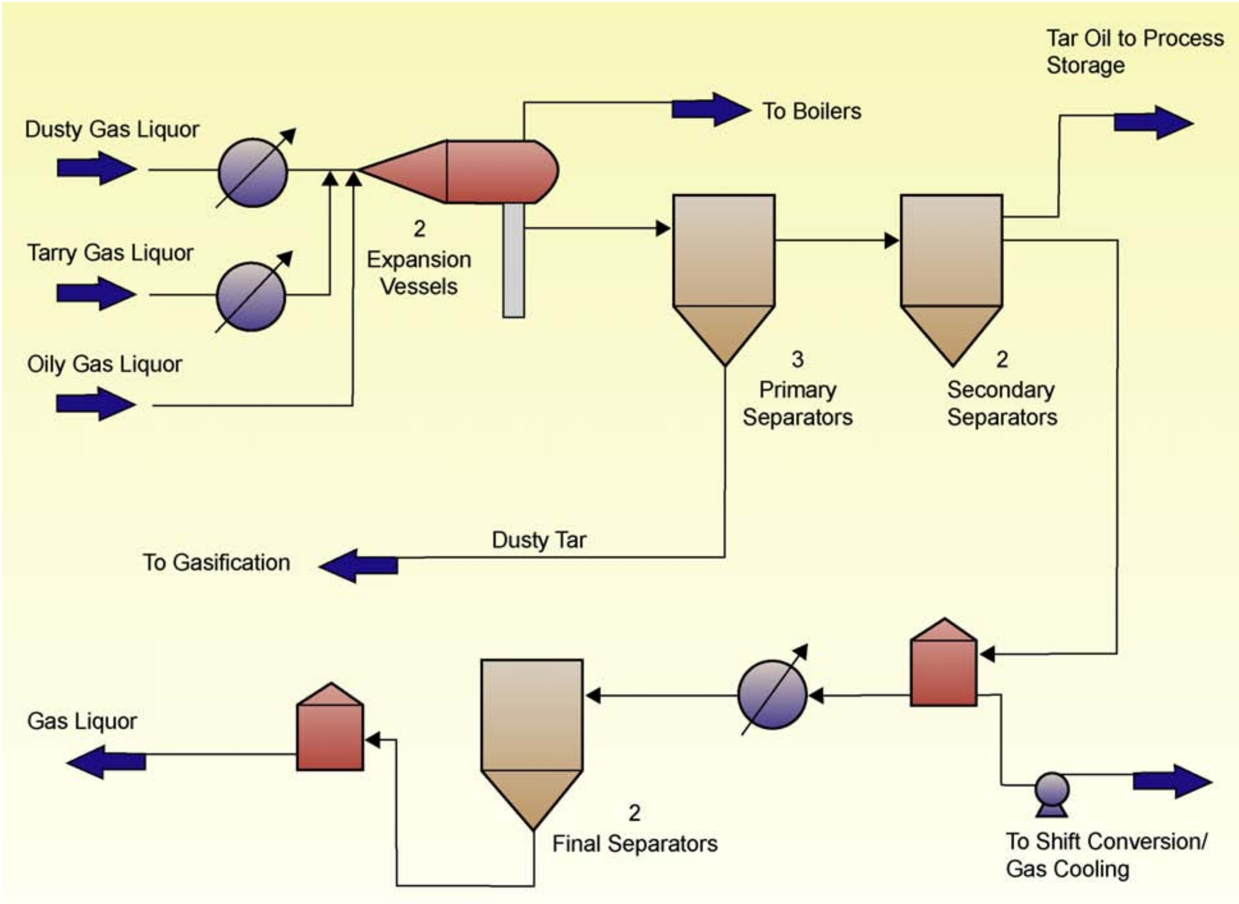
5.12 Gas Liquor Separation

5.12.a The Plan



The various gas liquor streams are sent to the gas liquor separation unit where they are cooled, combined, and depressurized. The total stream flows through a series of gravity separators where tar oil is removed by decantation. The tar oil is stored for later use as fuel in the plant's Riley Stoker boilers and two superheaters. A bottoms stream rich in coal fines and heavy tar is removed from the first-stage separators and sent back to the gasifiers for reinjection. The gas liquor from the final separator is sent to a 5 million gallon storage tank. From this tank, the gas liquor is passed through multimedia filters before being fed to the Phenosolvan unit. The diagram of this gas liquor separation unit can be seen below in Figure 17.

Figure 17: Gas Liquor Separation



5.12.b The Experience

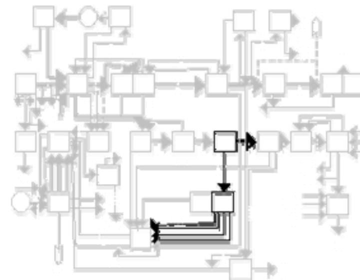
The Gas Liquor Separation Unit has not effectively removed as much oils and tars from the process water as had been hoped. At current feed rates, precipitation of tar and oil particles is not complete. The result is problems downstream in the processes which prepare the gas liquor for the cooling tower.

One issue noted during startup of the plant is that when the gasifiers are operating on air rather than oxygen, foaming and emulsification occurs in the separation vessels and prevents phase separation.

The expansion gases from the gas liquor separation unit were originally sent to the flare system, but are now recycled as fuel for the boiler unit.

5.11.c Implications for Future Projects

- DGC personnel report that many of the extraneous costs to run the DGC plant are due to liquids. Using a gasifier technology that did not create as many liquid by-products would mean no gas liquor separation, no wastewater treatment, no phenosolvan unit, simpler ash handling, and probably a cleaner cooling tower. In addition, the plant would not need nearly as many tanks and storage and handling facilities.



5.13 Phenosolvan

5.13.a The Plan

The primary function of the Phenosolvan unit is to remove crude phenols from the gas liquor by means of extraction with Isopropyl Ether (IPE). The leftover water goes to the phosam unit and then is used as makeup water in the cooling tower. Originally, the crude phenols were removed and used as boiler fuel.

5.13.b The Experience

Picture courtesy of DGC

Phenosolvan unit shortly after commission

The phenosolvan extraction unit has performed well. In early plant operations, occasional emulsion formation in the extractor prevented good separation, caused high IPE losses, and limited the throughput. Plant operators discovered that an excess of emulsifying agents caused the emulsion formation. High pH levels in the gas liquor caused polymerization of the higher phenols, which in turn facilitated the formation of emulsion. In addition, recycling of water from the multi-stage contacting unit aggravated the problem, as water-soluble oxygenates and hydrocarbons in the water polymerized to form emulsification agents. Eventually, plant operators abandoned the water recycling process and were able to lower the pH. Emulsions from the phenosolvan extraction unit were dramatically reduced.

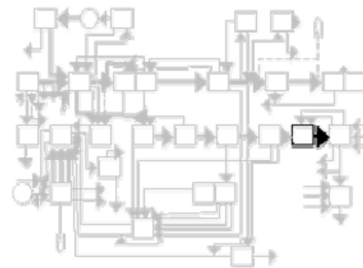
The plant has occasionally had problems with ether flowing into the water stream.

5.13.c Implications for Future Projects

- Lowering the pH of the gas liquor may eliminate emulsion formation.

- Water-soluble organic compounds are good emulsifying agents, and recycling streams, which contain these compounds, can cause emulsification.

5.14 Cooling Water System



5.14.a The Plan

Cooling water for the plant's circulating system is supplied from a 14-cell cooling tower. There are six main wastewater streams fed to the cooling tower: stripped gas liquor (SGL), dissolved air flotation (DAF) effluent, cooling tower blow down, Rectisol impure water, and reverse osmosis (RO) reject water. Stripped gas liquor from the ammonia recovery unit supplies a majority of the makeup water. Other process effluent streams are also sent to the cooling tower as makeup water. Blowdown from the cooling tower is sent to the wastewater treatment unit.

The cooling water system at the GPSP was a “pioneering effort” in multi-functionality. It was designed to provide cooling water for plant processes, reduce the volume of process wastewater by atmospheric evaporation, and biologically degrade hydrocarbon and water soluble organic contaminants contained in the tower makeup streams. The design allowed for the utilization of stripped gas liquor for makeup water.

5.14.b The Experience

In practice, the organic contaminants and hydrocarbons were not stripped as well as expected from the gas liquor. This has adversely affected heat exchange processes throughout the plant. The cooling tower has been a source of odor emissions, and the cooling water system can, at times, be a bottleneck to gas production.

Picture courtesy of DGC

Cooling Towers

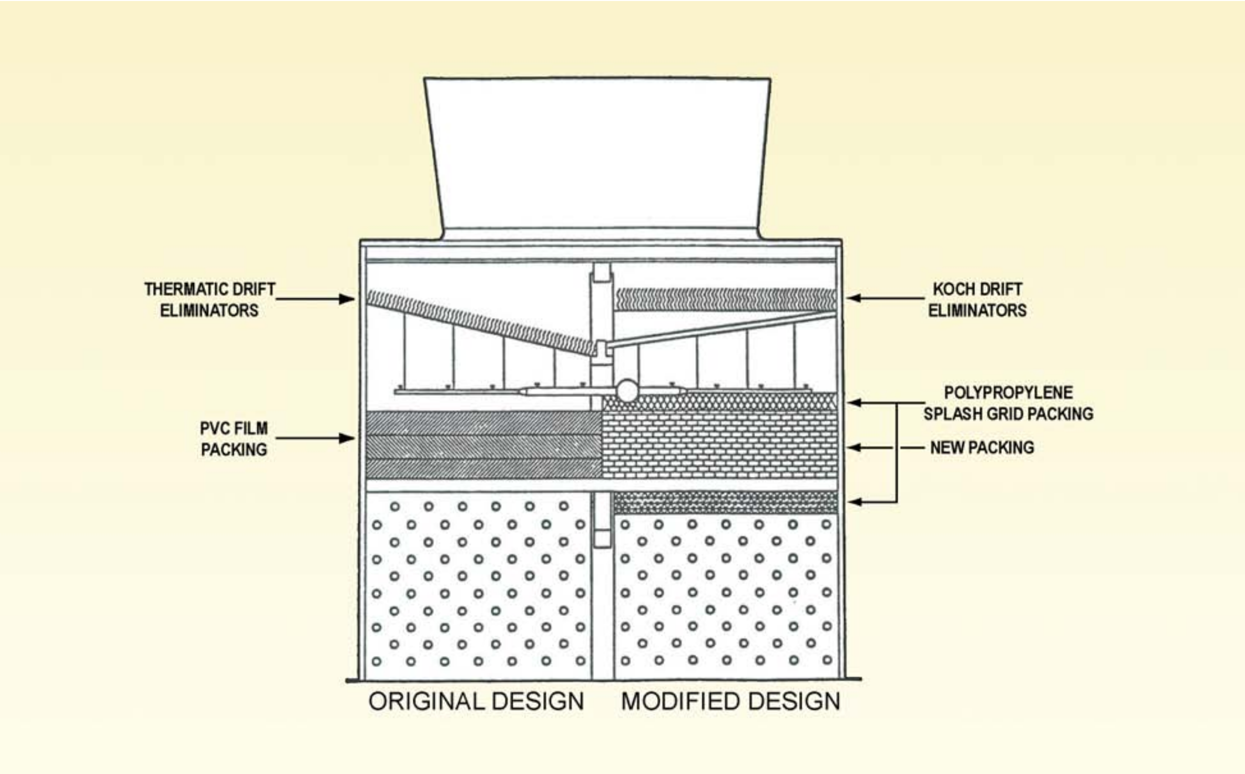
In early plant operations, the cooling tower experienced some difficulty with fouling and plugging in the polyvinyl packing due to higher than expected organic contaminants and the formation of yeast. The packing was replaced with ceramic tile splash packing, and some experimentation with biocide injection was undertaken. Eventually, it was found that the aerobic heterotrophic bacterial population had adapted to the point that improved digestion was occurring, and yeast formation was suppressed. Plant operators are currently replacing the ceramic tile splash packing.

Higher than expected drift loss from the cooling towers resulted in another system modification. The thermatic drift eliminators were replaced with Munters drift eliminators within the first year of the plant’s operation. A permanent wash system was also installed to prevent the formation of biofilm on the drift eliminators. During the writing of this report DGC was in the process of replacing the Munters with Koch drift eliminators. Koch drift eliminators were chosen over the Munters, despite the poor initial performance, due to their resistance to fouling. The performance of the Munters significantly drops below that of the Koch demisters when plugging occurs.

The cooling capacity of the cooling water system is a limiting factor for gas production during some summer months. Other changes to the cooling tower were implemented to increase cooling water system capacity. An air stripper was added to reduce odors coming from one of the makeup water streams in the plant's cooling towers.

In addition to modifications to the cooling towers, problems with the tower basin and sump pumps required modifications. The original two-stage, ½ inch mesh sump screens quickly fouled. Eventually they were replaced with six traveling screens. These screens captured solids and debris and backwashed it into a rotating drum strainer. Figure 18 is a schematic showing the changes from the original cooling tower design to the current design.

Figure 18: Original Cooling Tower Design and Final Configuration



In the original plant design, a liquid waste incinerator was built to incinerate organic contaminants in the cooling tower waste. However, repeated mechanical failures and high fuel costs for the incinerator eventually led to a reconfiguration in which the wastewater is injected into the gasifiers. The liquid waste incinerator has since been removed.

5.14.b Implications for Future Projects

- If a similar scheme is used in a future plant, DGC personnel recommended installing equipment or processes to clean up the water fed to the cooling tower, which has been a source of odor emissions at the plant.
- DGC operators also recommended a modular cooling tower setup or two-tower system so that some sections could be worked on while others were in operation.

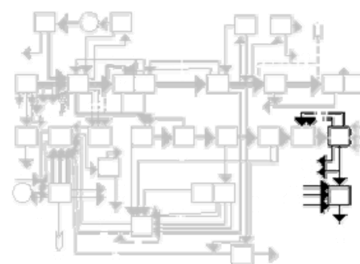
- The problems throughout the plant caused by excessive hydrocarbon and organic compounds in the cooling water emphasize the importance of effective gas liquor separation.

- A cooling system design that anticipates biofilm fouling in the sump screens may prevent the need for later modifications.

- Recycling waste liquids by reinjection into the gasifiers may be simpler than using a liquid incinerator.

- Control of bacteria is critical for proper operation. Key issues are monitoring and identifying contaminants, and identifying methods to restore the population.

5.15 Wastewater Treatment



5.15.a The Plan

Each of these cooling tower streams is treated in — or created in — a separate section of the wastewater treatment unit. The DAF system treats the water from the oily sewer collection system from the entire plant. The MEE treats the blowdown from the cooling tower. The RO reject water is from the secondary water treatment area. The three other wastewater streams are self-explanatory; i.e., the Rectisol impure water is from the Rectisol unit. These six streams are combined at the cooling tower and treated as mentioned below.

Wastewater from the plant is collected and recycled or disposed of in the wastewater treatment unit. Wastes from regeneration of anion and cation resins in secondary water treatment and boiler blow downs are injected down one of the deep wells after first being filtered and adjusted for acidity. The remaining wastewater is treated in a DAF unit, and then in a MEE unit. The concentrate from the MEE was intended to be disposed of by incineration in a liquid waste incinerator. The distillate from the MEE can be used as utility water throughout the plant or is returned to the cooling towers as makeup water.

5.15.b The Experience

The most notable problems with the wastewater streams were found in the oily water stream, and the cooling water system. The oily water stream had problems with the API Separator. The plastic scrapers on the separators became brittle and cracked. The plastic scrapers had to be replaced with carbon steel.

The problems with the fouling of the heat exchangers in the water-cooling system were due to small amounts of dispersed tar and grease. The containments were found to originate from the inadequate functioning of the SGL and the API separators. Other problems with the wastewater streams dealt with the liquid waste incinerator (LWI). As stated in the previous “Cooling Water System” section the LWI has been removed due to repeated mechanical failures and high fuel cost. The concentrate from the MEE now goes to the gasifiers.

5.15.c Implications for Future Projects

- Careful consideration of the API scraper materials will increase API separator reliability.
- Carefully monitoring the wastewater stream will reduce the contaminants.

5.16 Ammonia Recovery

5.16.a The Plan

Dephenolized gas liquor is sent to the ammonia recovery unit (also known as the Phosam Unit). In this unit, ammonia and water-insoluble acid gases are stripped. A circulating solution of lean Ammonium Phosphate is used to absorb the ammonia. The rich Ammonium Phosphate solution is stripped to remove ammonia; producing an aqua ammonia product, and to regenerate the Ammonium Phosphate solution.

5.16.b The Experience

Early on, this process experienced problems with the heat exchangers due to cooling water fouling and metallurgy issues. The second stage of the exchanger was built with carbon steel instead of stainless, and excessive cooling water fouling resulted. With decreased heat transfer capacity, ammonia had to be vented at times.

As described in previous sections, problems with the Stretford Unit resulted in a reconfiguration in which Rectisol acid gases were sent to the Riley Stoker boilers and a FGD unit was added to the boilers. Since ammonia was being recovered at the plant, managers made the decision to use ammonia scrubbers and to sell the ammonium sulfate by-product as a fertilizer. However, the ammonia recovery unit could not alone meet the ammonia needs of the FGD system.

With gas prices down in the late 1990s, an ammonia synthesis plant was installed in 1997 to increase ammonia synthesis capacity for the FGD unit and to diversify the plant’s product slate. Rectisol syngas was diverted from SNG production to feed ammonia synthesis. Excess anhydrous ammonia was sold as fertilizer. The ammonia synthesis plant is not tied into the Phosam unit in any way.

1100 ton-per-day ammonia production plant added in 1997

The ammonia synthesis plant has experienced some problems. The cryogenic system has been difficult to keep in operation, lowering the unit's overall efficiency. By 2002, DGC was planning on adopting a "block operation" scheme for the ammonia plant — running for three months at a time, followed by a three month shutdown — to take better advantage of seasonal fertilizer markets.

5.16.c Implications for Future Projects

- In an ammonia recovery scheme similar to the original design, the metallurgy in the heat exchangers is extremely important.

- There was widespread sentiment among DGC plant personnel that diversifying into anhydrous ammonia by installing an ammonia synthesis plant is not advisable in future projects. They noted that natural gas must be fed into the feed gas heaters for a period of time before the plant can start producing ammonia. It has been difficult to maintain the efficiency of the ammonia plant due to problems with the cryogenic system, and operation of the ammonia plant requires an estimated 20–25 additional employees.

5.17 Catalysts

5.17.a The Plan

Several processes use a catalyst in the operations of the GPSP. The shift unit utilizes a cobalt/molybdenum catalyst to adjust the ratio of H_2 to CO in the gasifier effluent to the correct value for the methanation reaction. Steam and CO react to produce hydrogen and CO_2. The methanation unit uses a nickel catalyst. The ammonia plant has several catalytic reactors and the methanol unit has a catalyst as well.

5.17.b The Experience

Overall the performance of the shift unit catalyst was good, and operators learned to predict when they need to change the catalyst based on the difference between the inlet and outlet temperatures of the unit.

Because nickel in its active form reacts with sulfur, chlorides, and other impurities, the feed gas to the reactors must be extremely pure. The first methanation catalyst at the GPSP lasted 85 days while the expected life of these catalysts is one year. After correcting several issues, the plant experienced longer catalyst life. One rapid catalyst deactivation was the result of a leak in the raw gas feed/Rectisol product gas exchanger. Analysis of the deactivated catalyst showed that sulfur poisoning was the main cause of the catalyst deactivation. As a result, technicians initiated a new protection program for more accurate and faster feed quality detection and monitoring. Currently, the plant expects a four-year life from the methanation catalyst.

A sulfur guard reactor with an online monitoring system may enable the capture of a large proportion of the sulfur in the guard reactor and alert operators of leaks; however, DGC has not yet found a cost-effective sulfur guard system for the specific sulfur species and operating conditions of the GPSP.

5.17.c Implications for Future Projects

- In the shift unit (as with most exothermic catalysts), the life of the catalyst can be found by monitoring the bed temperature profile. Initially the majority of the temperature increase is seen at the top of the bed. As the catalyst deactivates, the temperature change migrates down the bed. When the majority of the temperature increases approaches the bottom of the bed, the catalyst must be changed.

- A spare heat exchanger allows for switching of online exchangers, which then allows technicians to perform leak checks. This in turn can lead to longer catalyst life.

- Constant online analysis and monitoring of the feed to the methanation unit may avoid rapid catalyst deactivation as a result of sulfur poisoning.

- A sulfur guard reactor with an online monitoring system may enable the capture of a large proportion of the sulfur in the guard reactor and alert operators of leaks.

5.18 Controls

5.18.a The Plan

The GPSP has a Plant Monitoring System (PMS), which serves to carry out the function of acquiring, indicating, controlling, and reporting the various process parameters of the operating units of the plant. The overall setup was such that if any process change or upset occurs upstream from a particular unit, the operators can make the appropriate changes in their unit via the monitors and control schemes, thus mitigating the adverse impact of the change or upset.

5.18.b The Experience

As expected, control- and instrument-caused upsets were frequent at startup but gradually diminished as operations continued.

5.18.c Implications for Future Projects

- Developing balanced control schemes allows operators to respond to the requirements of other operational plant units.
- Proper control systems for gasification and purification processes allow the project to produce gas and to operate within environmental constraints.
- Good boiler controls allow for firing gas, liquids, and waste gas simultaneously or in the same boiler.
- Monitoring and analyzing systems help to maximize plant production, product quality, and personnel safety.

5.19 Maintenance

5.19.a The Plan

Due to the GPSP's remote location, onsite manufacture and repair of equipment and components is a necessity. Maintenance department personnel perform the maintenance and repair of the majority of equipment and facilities at the plant site. They provide these services both in the field and in various well-equipped shops including a machine shop, an electrical repair shop, an instrument repair shop, and a vehicle maintenance shop. The three major areas of maintenance activity at the plant are preventative maintenance, availability of spare parts, and scheduled turnarounds.

5.19.b The Experience

Preventative Maintenance: Managers defined major critical equipment that would require special attention; e.g., boilers, rotating equipment, heat exchangers, towers, vessels, compressors, etc. Management then established crews for each category of equipment. Also, management established a nondestructive testing group to test corrosion rates and project the expected life of equipment. These various task groups generate reports that are input into the computerized maintenance program that generates the general plant maintenance schedule.

Availability of Spare Parts: Prior to startup, GPSP hired a consultant to prepare a list of critical equipment and parts. Based on this, management established the sparing philosophy and the spare parts inventory. Bearings, instruments, pump parts, and heat exchangers were the items with the largest turnover. Management established an Inventory Control Group to re-evaluate the critical spare parts inventory status. It learned that the spare parts inventory requires updating every two years. Furthermore, it learned that about 20 percent of the spare items constituted 80 percent of the monetary value of the spare parts.

Scheduled Turnarounds: Scheduled turnarounds are planned periods when the entire plant or half of the plant is shut down to carry out major maintenance work that cannot take place while the plant is operating at the designed production rate. At the GPSP, managers schedule a major plant turnaround — usually a single train shutdown — when the heat exchangers require cleaning. Operators have found ways to reduce the turnaround time from the 12 days the process initially required. Technicians also check corrosion rates inside vessels, reactors, and other equipment during the turnarounds. Furthermore, during these turnarounds, technicians perform periodic inspections necessary for regulatory certification of equipment, such as boilers.

In June of 2004, the plant initiated the first planned shutdown of the entire plant in its history. Over a year of meticulous planning along with the help of numerous contractors resulted in a remarkably brief six-week outage. For many sections of the facility, it was the first opportunity to get a detailed picture of the conditions inside various vessels and pipelines. The two major results are as follows:

1. Plant production has increased significantly due mainly to re-traying of the Rectisol towers completed during the black plant; and

2. Twenty years between planned black plant shut downs may be somewhat longer than optimal.

5.19.c Implications for Future Projects

Preventative Maintenance

- Preventative maintenance is directly related to plant performance. As an example, due to high-quality preventative maintenance in addition to upgraded components, the GPSP is able to consistently run 13 or 14 gasifiers at a time as opposed to the 12 it was designed to operate at any one time.

Availability of Spare Parts

- Items that are frequently used — such as bearings, instruments, and pump parts — can severely hinder operations if replacement parts are not immediately available. Regular updating of the spare parts inventory helps avoid problems.

- Focusing on the frequency of replacing items with high monetary value can reduce the overall inventory of the plant by a significant dollar amount.

- When spare parts are delivered from overseas, planning for an extremely long delivery time and planning the sparing of those items accordingly can help avoid problems.

Scheduled Turnarounds

- Skill and experience can reduce the time required for scheduled turnarounds and also increase production rates during turnarounds in which only half the plant is shut down.

5.20 Data Management

5.20.a The Plan

A computer-based information system performs the data management processes at the GPSP.

5.20.b The Experience

The computer system undergoes updating as newer technology obsoletes older technology. The most recent update occurred in January 2004.

Major flow measurement devices at the plant are mostly differential-pressure meters, some of which use redundant transmitters and pressure and temperature compensation where appropriate.

Some difficulties have existed with the ability to closely monitor process flows in some areas of the plant. For example, syngas flows between the Rectisol unit and the methanation unit are not accurately metered. DGC operators report that the Annubar-type meters installed in this and other units have not been able to accurately measure flow. This makes the process of analyzing the performance of specific units much more complex.

5.20.c Implications for Future Projects

- As long as it does not significantly hinder process flows, the installation of frequent and robust meters throughout the plant allows for better analysis of energy balances and process optimization.

5.21 Human Resources

5.21.a The Plan

An original estimate for the number of required labor was set at 865 full-time employees. A first-of-a-kind plant like GPSP is often intentionally overstaffed during startup and initial operations. GPSP began operations with about 1,000 employees.

5.21.b The Experience

Plant officials now note that that, even during the plant's startup period, the staff could have been about 10 percent less without significantly affecting operations.

As the plant settled into routine operations, economic forces have encouraged DGC to trim its staff as much as possible. Technological improvements have allowed the plant's staff to be reduced without affecting operations or safety. For example, due to advances in computer control technology, the number of control rooms is now 5, as opposed to 11 in the plant's original configuration. Eventually, DGC was able to reduce the number of staff to 705.

Like other business decisions, staff size for a facility like the GPSP is a trade-off between the capability to perform more maintenance and to handle some capital improvement projects in-house, and reduced operating costs. DGC management stressed that once a plant like this is built, the only place to significantly reduce costs is in personnel, but that decisions need to be made with an understanding that safety and maintenance standards must be preserved.

5.21.c Implications for Future Projects

- DGC personnel suggested that a different gasifier system could mean much less labor for maintenance — possibly half as much as the current plant uses. It was also estimated that a gasification plant similar to the DGC plant could have 25–50 percent more capacity without requiring an increase in the number of operators.

- Management also pointed out that future plant designers might consider the fact that 80 percent of the plant costs are fixed, whereas labor costs can be reduced with increased efficiency and automation.

6. Products and Diversification

6.0.a The Plan

The initial four revenue by-products of the plant were anhydrous ammonia, sulfur, tar oil, and liquid nitrogen. In addition, the plant has always separated carbon dioxide for possible sale.

6.0.b The Experience

The plant's management under DGC has engaged in changes focused on limiting the plant's vulnerability to the volatile natural gas market. DGC has invested heavily in processes, equipment, and marketing for new or additional non-gas products. Some of these products are discussed in detail in the following subsections. Figure 19 below shows the chemical formula and maximum production rates for each of the GPSP by-products.

Figure 19: GPSP Non-SNG Revenue Products

By-products	Formula	Production
Ammonium Sulfate	$(NH_4)_2SO_4$	~110,000 tons/year
Anhydrous Ammonia	NH_3	~400,000 tons/year
Carbon Dioxide	CO_2	~40 billion scf/year (1.56 million tons/year)
Dephenolized Cresylic Acid	71% C_7H_8O 12% $C_8H_{10}O$ 8% $C_8H_{10}O$	~33 million pounds/year
Krypton and Xenon Gases	89% Kr 8% Xe	~3.1 million liters/year
Liquid Nitrogen	N_2	~200,000 gallons/year
Naphtha	43% C_6H6 18% C_7H_8 4% C8H_{10}	~7 million gallons/year
Phenol	C_6H_6O	~33 million pounds/year

6.1 Ammonium Sulfate

From very early on, the plant's Stretford system for removing sulfur from the Rectisol acid gases experienced problems with clogging and ineffectiveness. In 1996, the layout was altered so that the acid gases were sent straight to the plant's Riley Stoker boilers and a FGD unit was installed to scrub the flue gas from the boilers. The scrubbing section of the FGD unit is set up much like a conventional wet limestone forced oxidation unit with the exception that the FGD unit at the plant uses ammonia to scrub the SO_2 rather than limestone. Scrubbing the SO_2 with ammonia produces ammonium sulfate. The ammonium sulfate crystals produced in the scrubbing section of the FGD unit are sent to the dewatering and compaction section where ammonium sulfate granules are produced. These granules meet the specification for fertilizer-grade ammonium sulfate and are marketed as Dak-Sul 45, a trademarked product. The ammonium sulfate is shipped from the plant via truck or railways.

Production and sale of Dak-Sul 45 allows DGC to recover some of the costs of scrubbing the boiler emissions. The plant produces about 110,000 tons annually.

6.2 Anhydrous Ammonia

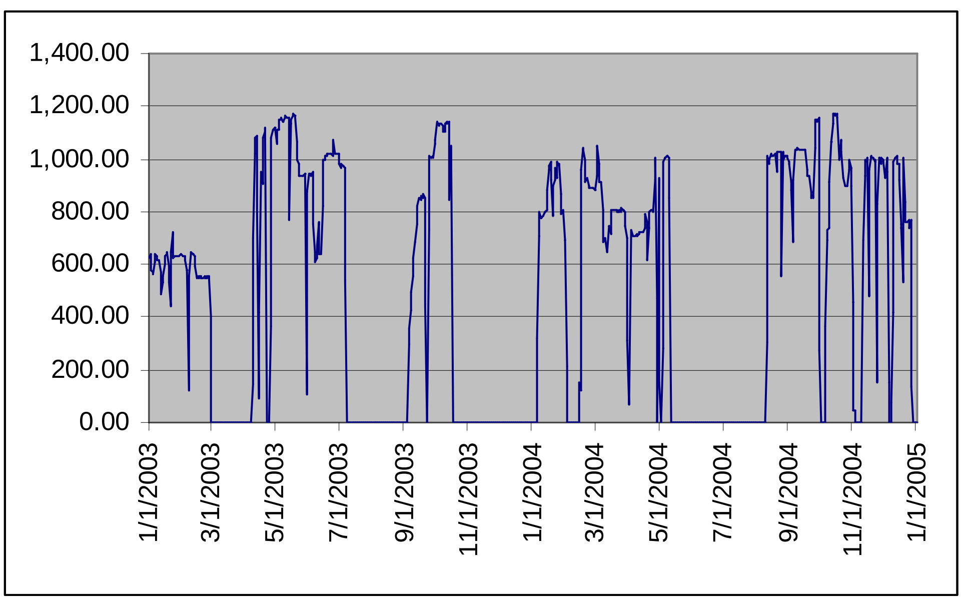
The FGD system needed slightly more ammonia for its scrubbing process than the plant's ammonia recovery unit was able to produce. Since diversification was already a stated policy of DGC, the decision was made to buy a used ammonia synthesis plant and install it at the plant. Starting in 1997, the ammonia plant tapped un-methanated syngas from the gasification process for synthesis into anhydrous ammonia, a marketable fertilizer and industrial process feedstock.

The ammonia plant has proven difficult to maintain and operate efficiently. Problems with keeping the cryogenic system (or "cold box") in operation have plagued the system since startup, and the unit runs much less efficiently without it. The anhydrous ammonia market has proven nearly as volatile as the natural gas market, and recent market trends have made natural gas a more profitable option than industrial ammonia. DGC and DOE managers suggested that diverting synthesis gases for producing anhydrous ammonia instead of natural gas may not maximize revenues. Some even suggested that the facility would have been better off with a conventional wet limestone scrubber and not expanded ammonia synthesis capacity.

The plant can produce as much as 400,000 tons per year with constant operation. However. in 2002, DGC began "block operation" of the Ammonia plant, running for three-month increments twice per year, in order to better take advantage of seasonal fertilizer markets.

Figure 20 shows ammonia production in tons per day over the last two years.

Figure 20: Ammonia Production (tons/day), 2003–2004



6.2.a Implications for Future Projects

- Diversification of products may be an effective hedge against volatile gas markets, but overreacting to market downturns by shifting away from natural gas production carries its own risks.
- Diversification plans that involve additional plant units and processes may add a level of complexity that overburdens plant and human systems and resources.
- Market location and transportation costs are determining factors in the decision to diversify.

6.3 Carbon Dioxide (CO_2)

"Lessons learned in the Weyburn Project are a starting point for 'FutureGen,' a $1 billion Energy Department project to develop efficient, nonpolluting power plants sometime after 2010."

"From Obsolete to Cutting Edge – Potential Coal Power Plant of the Future," Wall Street Journal, October 15, 2003

The GPSP has always had the ability, due to its Rectisol process, to separate highly pure, dry CO_2 for possible sale. However, no viable market for the gas was identified until the late 1990s. In 2000, DGC began selling CO_2 to a Canadian oil field for enhanced oil recovery (EOR). Shipped through a 205-mile pipeline, the 105 million standard cubic feet per day sent to the oilfield represents about 60 percent of the total CO_2 produced by the plant.

The use of CO_2 to increase oil production is not a new technology. The process was first demonstrated in 1972 in Texas. Supercritical CO_2 injected into the oil field acts as a solvent, dissolving residual oil and reducing its viscosity so that the oil is more easily pumped from an aging reservoir. However, natural CO_2 resources are often located too far from oil fields to be used. Other CO_2 sources, such as stack gases from power plants, contain too many impurities and too much moisture to be economical for EOR. GPSP, however, produces CO_2 that is about 95.5 percent pure and contains very little moisture — the dew point is -100ºF. In addition, several mature oil fields lie in the Williston Basin, which extends from northern North Dakota and Montana into Saskatchewan and Manitoba.

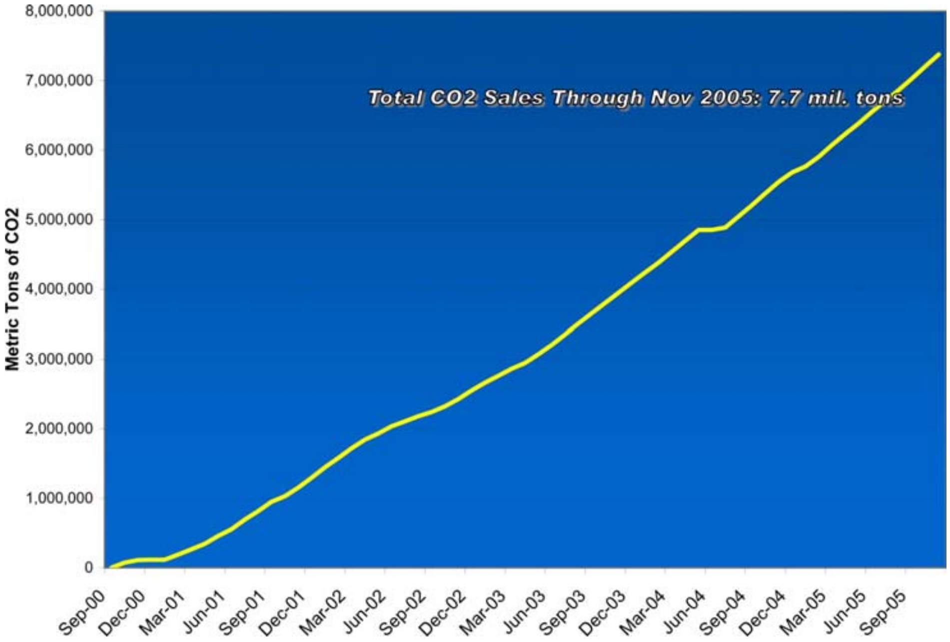
EnCana (formerly PanCanadian Resources), based in Calgary, Alberta, faced declining production in its aging Weyburn, Saskatchewan oil field. This company, along with DGC, saw opportunity to use CO_2 produced at DGC's gasification plant for EOR and a demonstration of carbon sequestration. In 1997, the two companies came to an agreement in which DGC would build a 205-mile long pipeline to ship its CO_2 to EnCana's Weyburn Oil Field. EnCana would then use 95 mmscfd for enhanced oil recovery.

DGC hired ENSR, an environmental consulting company, to prepare the required environmental assessments and permit applications in North Dakota and Saskatchewan. DGC had to secure permission or agreements from the International Boundary Commission; North Dakota Public

Service Commission; North Dakota Water Commission; North Dakota Historical Society; U.S. Army Corps of Engineers; U.S. Department of the Interior/Bureau of Land Management; U.S. Forest Service; Canadian National Energy Board; and over 300 land owners in the United States and Canada. Rigorous safety measures were designed into the pipeline, including leak detection systems and a reverse 911 system. DGC formed a subsidiary, Souris Valley Pipeline Ltd., to own the Canadian portion of the pipeline. Pipeline Construction began in May 1999. Figure 21 shows the pipeline route. Two 19,500 horsepower compressors were installed at the plant, each with the capacity to discharge 55 mmscfd of CO_2 at a pressure of 2,700 psig. CO_2 deliveries began in September 2000. Figure 22 charts the upward trend of CO_2 sales since deliveries began.

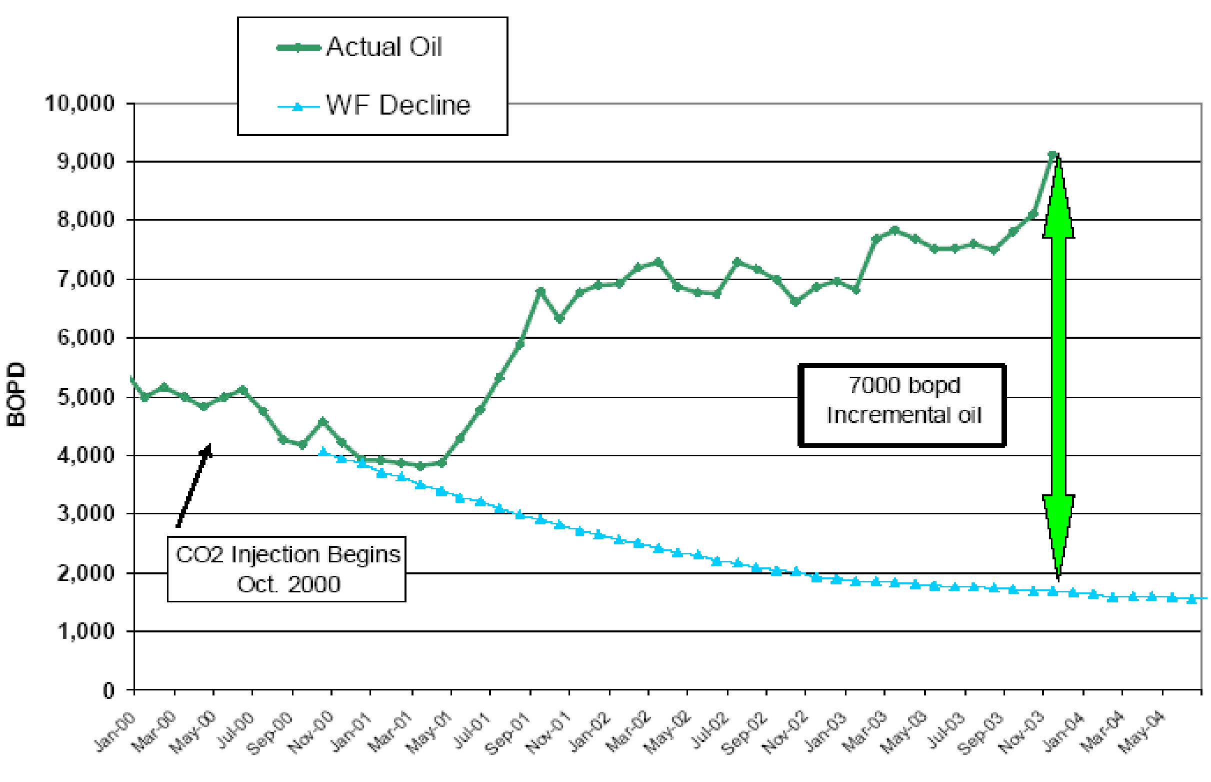
Figure 21: CO_2 Pipeline Route

Figure 22: Cumulative CO_2 Sales, 2000–2005



EnCana estimates that the agreement with DGC will allow the fields to produce an additional 130 to 140 million barrels of crude oil. Figure 23 below shows the significant enhancement to oil recovery that the Weyburn Fields have achieved since CO_2 injection began. The blue line represents the projected oil recovery without the CO_2 injection.

Figure 23: Oil Recovery Increases Due to CO_2 Injection



In addition to the benefit of enhanced oil recovery, the agreement with EnCana means that the GPSP is one of the first facilities in the world to engage in the sequestration of carbon emissions that would otherwise have been released to the atmosphere. CO_2 emissions from the plant, factoring in flaring at the oil fields, the energy consumption of the CO_2 compressors, and make-up boiler fuels, are down 30 percent since 2000. Through the end of 2005, over 5 million tons of CO_2 had been sequestered.

The pipeline and compressors cost DGC an initial investment of about $100 million, and DGC expects to see increased net revenue from the sale of CO_2.

6.3.a Implications for Future Projects

- Enhanced oil recovery represents an important potential market for a CO_2 product from a gasification process.
- Engaging in a CO_2 sequestration agreement is significant in minimizing the environmental impact of a gasification plant.
- Healthy communications of the right-of-way acquisition team to the landowners can avoid the need for condemnations in the acquisition of the pipeline route.

- Compensating landowners on a dollars-per-acre basis, dependent upon the type of land, can aid in the acquisition process.

6.4 Other Products

In 1991, a phenol purification unit came online to purify the crude phenol stream into phenol and cresylic acid, each of which is a marketed by-product. Operations personnel report that the unit has functioned well. Phenol is separated from the hydrocarbon stream that flows from the Phenosolvan unit to the boilers as fuel. The plant processes about 33 million pounds of phenol per year, and ships the product as a liquid by rail tank car. However, DGC personnel report that the market for phenol is a buyer’s market in which the supply often outpaces demand.

The plant produces a similar amount of dephenolized cresylic acid from the same stream. The market for cresylic acid has been much more consistent than phenol markets, according to DGC. The cresylic acid is also shipped from the plant by rail.

The GPSP air separation unit also provides some marketable by-products in the process of separating oxygen for the gasifiers. About 24 million gallons per year of liquid nitrogen are produced but only about 200,000 gals are available for sale. The plant also sells about 3.1 million liters per year of krypton and xenon to Praxair Ltd. for use in lighting and optical processes.

The plant produces about seven million gallons of Naphtha per year. Naphtha is primarily a mix of benzene, toluene, and xylene used in refining processes, and DGC reports that regional and national markets have been very strong. Some naphtha is used within the plant as boiler fuel, but up to 75 percent of the production is sold.

6.4.a Implications for Future Projects

- A gasification plant can offset some costs of air separation processes by selling by-products such as liquid nitrogen, krypton, and xenon. Argon and liquid oxygen may also be viable products.

Appendix 1: Pre-Operational Planning

The experiences described in this section are based on the time period of 1977–1988 and are taken mostly from the lessons learned report assembled by Fluor Technology, Inc. in 1988. Information gathered from interviews with DGC management is included as well. However, it is the experience of operating the plant for 20 years that gives many of the DGC operators and managers a perspective that is unique in the industry, so knowledge gained during these pre-operational phases is confined to this Appendix.

A1.1 Coal

A1.1.a The Plan

With the target market set as the mid-northwest area of Michigan-Illinois-Wisconsin and gasification system planned, GPSP chose the lignite fields in North Dakota as the source of coal for the project. They chose the western coal over the eastern coals of Illinois, Ohio, and West Virginia based on its proximity to the targeted SNG market and inherent suitability of the coal for gasification. Planners found that the eastern coals were not as technically well suited for the proposed gasification process as the western coals and additionally, mining costs were much less for the western coals than for the eastern coals.

In May 1972, ANR obtained options for the coal from Coteau Properties Company. They conducted exploration in stages, which consisted of drilling and coring of the coal seams to obtain samples for coal quality and thickness determinations. This exploratory drilling confirmed that the deposit contained lignite quality coal. ANR conducted detailed chemical analyses on the lignite to assess heat content as well as chemical and physical characteristics.

The coal samples yielded characteristics as shown below.

Figure 24: Coal Sample Characteristics

Constituent	Wt %	Element	Wt %
Moisture	34.30	Carbon	72.90
Ash	9.50	Hydrogen	4.60
Fixed Carbon	28.80	Oxygen	19.80
Volatiles	27.40	Nitrogen	1.40
Total	100.00	Sulfur	1.30
		Chloride	0.02
HHV, Btu/lb	6,744	Total	100.00

A1.1.b The Experience

During the first full year of operation of GPSP, the gasification unit processed 4,759,124 tons of lignite. The weighted average analysis of the lignite feed on a quarterly cumulative basis showed that the core samples accurately predicted the actual average lignite composition, except the ash content, which was lower than predicted. Furthermore, the actual lignite had slightly higher carbon content than expected while the hydrogen, nitrogen, and sulfur contents were lower than expected. In total, the lignite was of higher quality than expected.

Further information was necessary. Planners required the breakdown of sulfur into organic, pyritic, and sulfate species to provide insight into the type of sulfur compound that may form in the gasifiers, which would affect the design of downstream sulfur removal. Furthermore, a friability test on freshly mined and on partially dried lignite would help to identify the extent of fines that the coal will generate during crushing and handling operations.

A1.1.b Implications for Future Projects

- The breakdown of sulfur species such as organic, pyritic, and sulfate is useful to design basis coal analyses for coal gasification plants.
- Coal friability tests help to establish the amount of fines that the coal will generate during crushing and handling operations.
- Coal quality can vary during the mining operation, which will result in a range of values, instead of a single value, used for the design of various process units.
- Plant officials noticed during the first year of large-scale operation that lignite undergoes degradation upon storage and/or transportation. This degradation manifests in size reduction, drying, and dusting, which in most cases adversely affects the gasification process. Minimizing the storage and handling of the lignite before gasification will minimize this degradation.

A1.2 Siting

A1.2.a The Plan

GPSP began selecting possible sites for coal conversion based on eight main factors. These factors include the following:

1) Raw Materials,

2) Marketing of Products,

3) Land Availability,

4) Environmental Considerations,

5) Construction Conditions,

6) Soil and Terrain Variations,

7) Supporting Facilities, and

8) Weather and Climate-Related Matters.

The major raw materials needed for synthetic natural gas manufacture are coal and water. These materials must be available at a reasonable cost. As a result, planners examined locations as near to abundant coal and water sources as possible.

Early marketing studies showed an imminent gas shortage in the mid-northwest area of Michigan-Illinois-Wisconsin. This prediction established the marketing area for SNG.

The original plans called for a site of 1,000 acres, half of which was for buildings, process units, and storage while the remaining half was for parking, construction laydown, and further expansion. Such a significant quantity of land required a reasonable cost per acre. In densely populated areas it is not easy to find available land of this size and what land is available is expensive.

Environmental regulations posed a major decisive factor in locating sites for the new plant. The Clean Air Act makes locating new plants very difficult in areas where emissions from existing plants have caused one or more of the criteria pollutants to be at a concentration that exceed federal/state ambient air quality levels.

The basic factors that contributed to optimal construction conditions were an adequate number of local craftsmen to staff the proposed project; an economic labor force defined as the optimal combination of wages, benefits, and productivity; a minimum of climatic impacts to design and construction progress; and maximum local auxiliary facilities in the form of shops, warehouses, shipping and receiving depots, and equipment and material suppliers, as well as community facilities to provide worker needs.

The design plant called for a single elevation for the entire plant. Planners searched for sites which would require a minimum amount of leveling. Furthermore, planners required the proposed site to have soil that could support the foundations of the process equipment.

Storage, roads, railroads, infrastructure, sewage, and other supporting facilities were important to site selection. The new site would need ample land for such facilities.

Weather and climate-related considerations also played a part in selecting a site for the gasification project. Winterization of process equipment can increase investment costs considerably. Also, cooling tower water losses are directly proportional to average ambient temperature and wet bulb temperature. Elevation of the site determines barometric pressure, which in turn influences design features of equipment and control instruments.

A1.2.b The Experience

GPSP selected the Beulah, North Dakota site as the best combination of availability and distance to raw materials, distance to product markets, land considerations, environmental considerations, construction considerations, soil and terrain variations, supporting facilities, and weather and climate related matters.

Planners found that the Beulah, North Dakota site was within economical distance to both of the primary raw materials. Coal from the nearby lignite mines required minimal transportation to the plant. The Michigan-Wisconsin Pipe Line Company acquired a permit from the state Water Commission for 17,000 acre-feet of water from Lake Sakakawea, which was 10 miles from the plant site. Labor and equipment were plentiful in this area because of recent power plant construction.

The marketing area for SNG was the mid-northwest area of Michigan-Illinois-Wisconsin due to the predicted gas shortage in that area. Because the North Dakota lignite reserves were the closest to the selected market area of the considered mines, planners selected the general location of North Dakota for the new plant site. In addition, locating the plant adjacent to the lignite mine means greatly reduced transportation costs and possibly improved cooperation between mining operations and crushing and blending operations for optimized fuel characteristics.

The region near the lignite deposits in North Dakota was predominantly an agricultural area with low population density and, therefore, sufficient land at a reasonable cost was available in this area. Furthermore, the higher than anticipated wastewater effluent rates and associated disposal problem, requiring an additional deepwell and pond, cannot be attributed to site-related causes. The prudent choice of the plant site ensured that crews could construct another deepwell and pond at the site without any problem. The Beulah site was the most economically feasible selection in regards to environmental considerations and impact.

The Beulah site, in spite of its remoteness, did offer some attractive features from a construction standpoint. The Basin Electric Power Cooperative and Montana-Dakota Utilities built several large power plants in the Beulah area at about the same time as GPSP. These projects started to bring infrastructure as well as workers to the area.

The Beulah site was a relatively flat terrain and therefore needed minimum ground leveling work. Core samples drilled show no lignite deposits at a reasonable depth below the plant site, so the facility would be built near but not over its potential feedstock, in an area central to extensive known lignite seams.

The Beulah site provided ample land for storage, roads, railroads, infrastructure, sewage, and other supporting facilities. The Burlington Northern railroad spur was nine miles to the plant and extension of the track did not pose any difficulty. Additionally, crews built an extra six-and-a-half miles of roads without significant problems. Furthermore, advanced planning overcame the absence of supporting infrastructure, such as accommodations to house construction workers, in the construction phase without major difficulty and without any adverse impact to the community. Also, DGC managers praise the idea of co-locating the plant with a power plant, noting that the power plant’s capability to use the coal fines that the gasification plant is unable to process saves substantial amounts of money. This also provides a reliable power source, which is critical to the efficient operation of the plant.

The severe winter conditions of the North Dakota site required enclosure of a number of process units, such as the gasification area. Also required were steam tracing and insulation of lines. Also, enclosure of rotating equipment and high maintenance areas was mandatory. An unusually harsh winter during construction caused some delays, but contractors overcame the problems and ultimately the severe climate did not cause a lengthening of the construction period. The plant was finished on time and under budget.

A1.2.c Implications for Future Projects

- The grading work provided for one elevation level for the entire plant. This was advantageous in many respects. However, for the ash disposal from the gasifier, a natural drop of level would help the ash transport in the sluiceways. This would eliminate certain ash handling problems at the expense of higher site preparation costs.

- Plant engineers suggest that, for a similar production level, a footprint much smaller than the 1,000 acres the current plant uses is possible. A new plant similar to the DGC plant may be smaller, with shorter pipe racks.

A1.3 Plant Size and Layout

A1.3.a The Plan

The GPSP was envisioned to have two "mirror image" plants, each with 14 gasifiers. Each section was to contain two product trains. The two product trains were included to make the plant operations more robust. The trains accomplish this by operating off two different energy sources: one on steam and the other on electricity.

A1.3.b The Experience

For various reasons, the second unit of the facility was never built. From an operational perspective, the size and layout of the GPSP has worked well. The two-train scheme has allowed for greater flexibility with conducting plant maintenance and upgrade projects while continuing to deliver product to the pipeline.

A1.3.c Implications for Future Projects

- Sizing plant based on available sizes of components, such as compressors, will maximize efficiency.

- The output level of the coalmine will also determine plant size. For example, will the mine operate one dragline or two? What are the needs of a co-located power plant or other mine-mouth operations?

- The managers interviewed for this report unanimously supported the idea of the plant operating in at least two trains. Although it was estimated that operating in a single train could save substantial labor costs, and although some reported that there was seldom a problem that requires shutdown of a whole train, it was concluded that the cost of the risk of zero-product plant outages exceeds the potential labor savings.

- In addition to the cost of product outages, operational systems can be affected by periods of inactivity; therefore, the benefits of having two trains can be viewed in terms of operational in addition to revenue.

- The idea of more interconnections between the trains for more flexibility was also suggested by plant engineers.

- Planning for the consumption or disposal of coal fines (in a gasification scheme that is sensitive to the fines) will also determine sizing issues.

A1.4 Recruiting and Training

A1.4.a The Plan

Due to the remote location of Beulah and the relatively harsh climate, management encountered great difficulty in attempting to establish a core of experienced people. Management trained its personnel mainly in-house.

A1.4.b The Experience

Management hired most of the facility's employees locally in a very successful campaign to recruit capable labor. Most of the plant's management team was composed of non-local experienced engineers.

Management accomplished the training of both inexperienced and experienced personnel at all levels largely through in-house resources such as manuals, lectures, company instructors, etc. Additionally, they used custom-developed or commercially available systems, including trailers with process simulators.

Companies participating in the construction of the plant provided invaluable training and knowledge transfer. SASOL, Linde, Lurgi, and numerous other vendors and process suppliers provided onsite expertise to aid in the startup of the plant.

The success of the recruitment plan is evidenced by the low rate of turnover at the plant. In 2004, DGC reported that over 230 workers, or about one-third of the plant's workforce, have over 20 years of service at GPSP. Since 2000, workers at the plant have been members of the International Brotherhood of Electrical Workers.

A1.4.c Implications for Future Projects

- The result of a local recruiting plan targeting capable yet inexperienced people can result in a well-balanced, well-trained, capable, and stable workforce.

- The training program resulted in near-total continuity between classroom and job assignment and excellent relations across the labor/management interface and between groups/departments. The use of "home developed" materials and personnel to perform training resulted in good understanding of the plant and its units on the part of the trainers, as well as large saving in money which otherwise would have been spent on professional training.

A1.5 Gasifier Selection and Testing

A1.5.a The Plan

ANG chose the Lurgi moving bed gasification process primarily because it was the only established gasification technology available at the time.

ANG carried out several testing programs in connection with the design of the gasification plant. The first major program was testing of GPSP lignite in a commercial size Lurgi gasifier at the Sasol One plant at Sasolburg, Republic of South Africa. The second major program was testing the use of stripped gas liquor for cooling water makeup at the University of North Dakota Energy Research Center and at Sasol One.

A1.5.b The Experience

The lignite testing required transporting 12,000 tons of lignite from North Dakota to the Sasol One facilities. At the Sasol One plant, the lignite, after screening, fed to one of the commercial size Mark IV gasifiers. The lignite underwent testing under normal production mode operation at different feed rates and at various steam to oxygen ratios. Operators analyzed the product raw gas and recorded the characteristics of the gasifier ash at the various operating modes.

The test showed that lignite was a suitable feed for a commercial-scale Lurgi moving bed gasifier. The test also showed that North Dakota lignite with moisture content over 35wt percent could gasify without special pretreatment. Additionally, the test provided actual full-scale operational data on the required steam to oxygen ratio, product raw gas composition, and overall liquid hydrocarbon yields. However, the test either did not detect the high mercaptan concentration in the raw product gas or technicians did not realize its significance. Early identification of this problem could have provided incentive to predict the potential distribution of the mercaptans in the Rectisol unit effluent streams.

The gas liquor test at the University of North Dakota Energy Research Center was a pilot plant type operation in which an oxygen blown, slagging fixed-bed gasifier operated on 2,000 lb/hr of GPSP lignite feed to produce effluents for characterization, treatment, and reuse studies. Researchers used gas liquor from this process as makeup to a forced draft pilot cooling tower in order to investigate the process performance and environmental aspects of a wastewater-fed cooling system. The tests indicated that additional treatment of the stripped gas liquor would be beneficial before feeding this stream to the cooling tower.

The Sasol One tests were pilot scale tests that utilized three small sized cooling towers, each rated at an evaporation rate of two gallons per minute. Cooling tower testing included the use of film packing and splash grid. With film packing and no biocide injection, biological slimes quickly plugged the cooling tower packing. With splash grid and no biocide addition, the cooling tower did not plug quickly with biological slimes. With no biocide injection, the heat exchangers developed a high fouling rate within several months due to biological slimes.

A1.5.c Implications for Future Projects

- Even an extensive commercial-scale test may not provide all the data required for the design of a first-of-a-kind project, such as the mercaptan problem in the raw gas stream.

- In light of the cooling water fouling problem experienced at the Great Plains facility, pilot scale tests were good directional indicators of what may happen in commercial operation.

- ANG chose the Lurgi gasification process because it was the only well-established gasification technology available at the time. Currently, more gasification technologies offer potentially viable alternatives. Some gasifiers, however, cannot work with all types of coal. Most gasifiers have not undergone testing on all coal types. Figure 25 below is a table showing alternative gasification technologies and the coals that have been tested.

Figure 25: Alternative Gasification Technologies

Gasifier Type	Feedstocks Tested
General Electric	Illinois No. 6, Pittsburgh No. 8, Kentucky No. 9, Kentucky No. 11 bituminous coals
E-GAS	Peabody's Hawthorn Mine, seam No. 6 high-sulfur bituminous
Shell	Bituminous
KRW	Southern Utah Bituminous and Eastern Bituminous
TRIG	Powder River Basin Sub-Bituminous, Illinois #6, Alabama Bituminous
Lurgi Dry Ash	Lignite
Prenflow	Coal and Petcoke

A1.6 Initial Costs and Financing

A1.6.a The Plan

The project in North Dakota ran into financing difficulties. As an unproven process, traditional lenders were hesitant to back the capital costs of the plant. To secure financing, ANG formed a partnership with several other natural gas utility companies (called Great Plains Gasification Associates or GPGA) so that DOE could back funding for the plant based on a large number of rate-paying customers.

Since financing depended on the ability to prove some level of system reliability, steps to create redundancies were undertaken in the plant's design. The plant was designed with two product "trains" so that natural gas would continue to flow even when maintenance workers were working on sections of the plant. The general idea was that at least half of the plant would be operable 100 percent of the time.

The design and construction process for the plant cost about $2 billion.

A1.6.b The Experience

After only a year of operation, amid falling energy prices, GPGA backed out of the plant and turned it over to DOE. While the plant kept operating under DOE control, studies were instituted on alternative uses of the plant. For example, a Department of Defense (DoD) study concluded that for an investment of $160 million, the plant could be converted to production of jet fuel.

DOE formally purchased the plant at auction in 1986, and announced plans to sell it in 1987. BEPC, which stood to lose 90 MW of electricity sales from the Antelope Valley Station if the adjacent gasification plant closed, and which already had a generation surplus, bought the gasification plant from DOE in August 1988. The power station also shared facilities with the GPSP, including water systems, and feared the impact of the plant's closure on mining operations. Part of the purchase agreement entitled the DOE to a share of the profits from the plant for approximately 20 years, in order to recover some of the capital costs of the plant. BEPC formed a Synfuels subsidiary, the DGC, to operate the plant.

A1.6.c Implications for Future Projects

- The GPSP is the pioneering coal-to-natural gas facility in the United States, and has proven its reliability during 20 years of virtually constant operation. With its achievements, similar future projects seeking financing can at least have a case study to point to. However, new gasification techniques that are much different from the process used at the DGC plant continue to evolve and may have greater potential for efficiency and profitability. Some of the new gasification processes remain unproven at the commercial scale, and future projects intending to use advanced processes may face the same difficulties securing financing that ANG faced.

A1.7 Environmental Permitting, Monitoring, and Compliance

A1.7.a The Plan

The federal, state, and local governments required a large number of permits for construction and operation of the Great Plains Gasification Project. The federal government required 9 permits, the state government required 31 permits, and the local government required 14 permits.

The federal and local permits required very little monitoring after the plant went into operation. The state permit conditions, however, required an extensive effort by GPSP personnel to satisfy monitoring requirements, new permit applications, and negotiations and renewal of existing permits.

A1.7.b The Experience

ANG prepared the necessary reports and letters covering the results of environmental monitoring and compliance tests to meet permit requirements. ANG then issued these documents to the North Dakota State Department of Health for review. ANG further prepared monthly and quarterly reports summarizing the environmental/health information for those periods of time. Additionally GPSP environmental and health personnel gave a formal presentation to DOE's representatives each month covering summary of pertinent environmental/health information for that period.

DGC experienced extensive difficulty in lowering sulfur emissions below the permitted level. This problem required substantial changes to the plant to fix. The sulfur dioxide emissions did not meet North Dakota State Department of Health permit conditions due to poor performance of the Stretford Unit. This led to the eventual reconfiguration of the plant such that acid gases from the Rectisol unit were delivered to the Riley Boilers, and a FGD unit was added to scrub the boiler stack gases. A Wet ESP was added to the FGD system to eliminate fertilizer particle emissions. The eliminated fertilizer particles were creating a visible plume emitting from the plants main stack.

A1.7.c Implications for Future Projects

- DGC personnel estimate that the permitting process for a new coal-to-natural gas facility similar to the DGC plant would take at least two years.
- Although the technologies involved are now better known, environmental permitting may prove just as difficult in the future because of changing political views on environmental issues.
- A good overall working relationship is essential between management and the state department of health due to extensive monitoring, compliance testing, quality control, reporting, and permitting requirements.
- Frequent, detailed communication with surrounding communities is essential for dealing with issues such as noise or odor problems and the effects of the plant on local infrastructure.
- In the original GPSP design, engineers designed one deepwell injection system for disposal of inorganic brine from the water treatment area and excess distillate from the multiple effect evaporators. Management had to permit for and install a second deepwell when the boilers generated an additional amount of blowdown water. This second deepwell has provided better redundancy for water treatment processes.

Plant personnel must perform environmental compliance tests to evaluate the emissions from each major system. Government requires these compliance tests prior to the issuance of the Permit to Operate.

Appendix 2: Number of Days at Zero Production By Year 1984 – 2005

Year	Days	Notes
1984	18	(Started Production on 7/27/84)
1985	1	
1986	0	
1987	0	
1988	18	
1989	0	
1990	0	
1991	4	
1992	0	
1993	0	
1994	0	
1995	0	
1996	7	Scheduled 'brown plant'
1997	0	
1998	0	
1999	0	
2000	0	
2001	0	
2002	0	
2003	0	
2004	48	Scheduled 'black plant' maintenance turnaround
2005	7	
	103	**Outage days out of 7,828 days since operations began.**
	98.7%	

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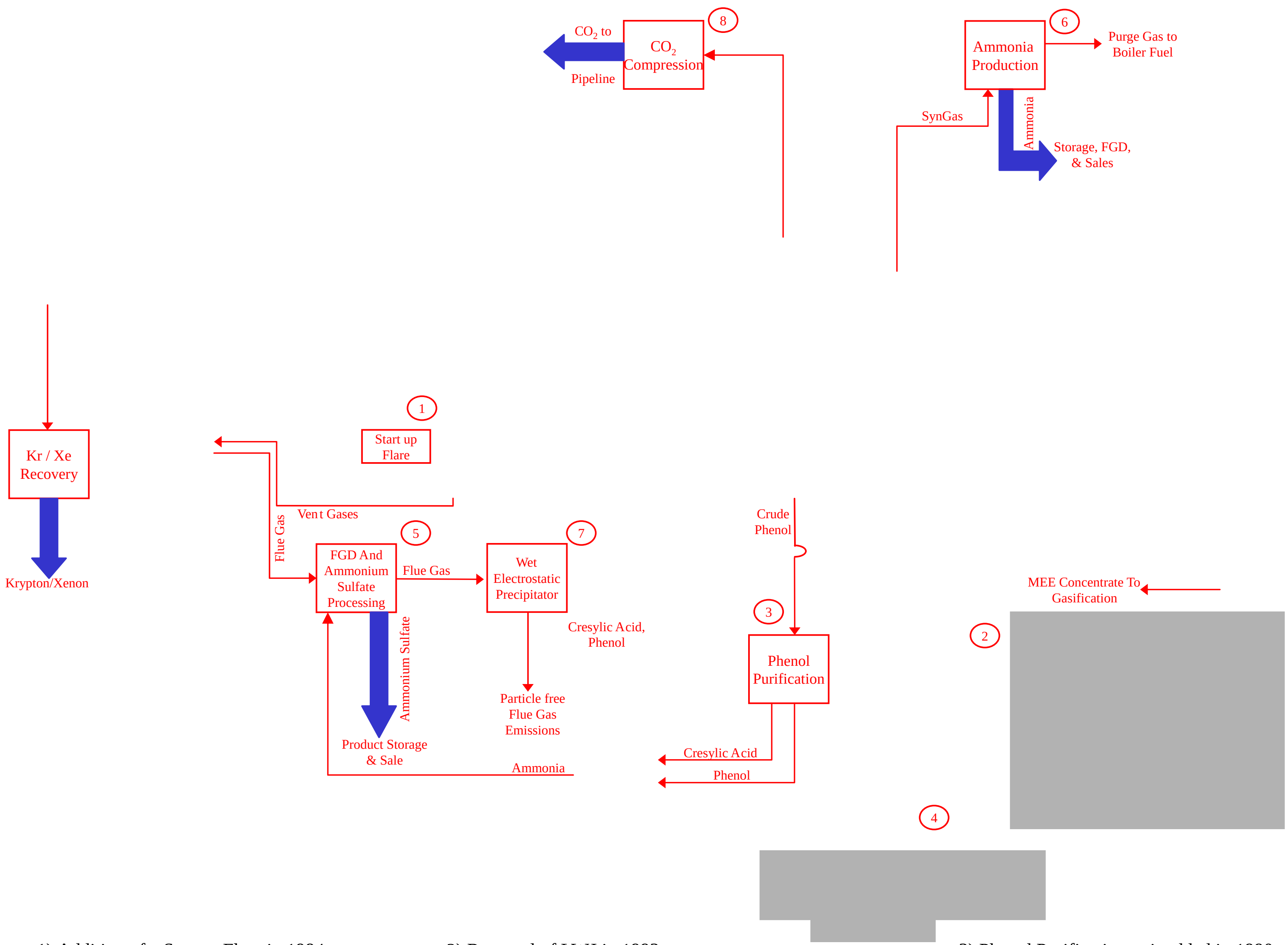
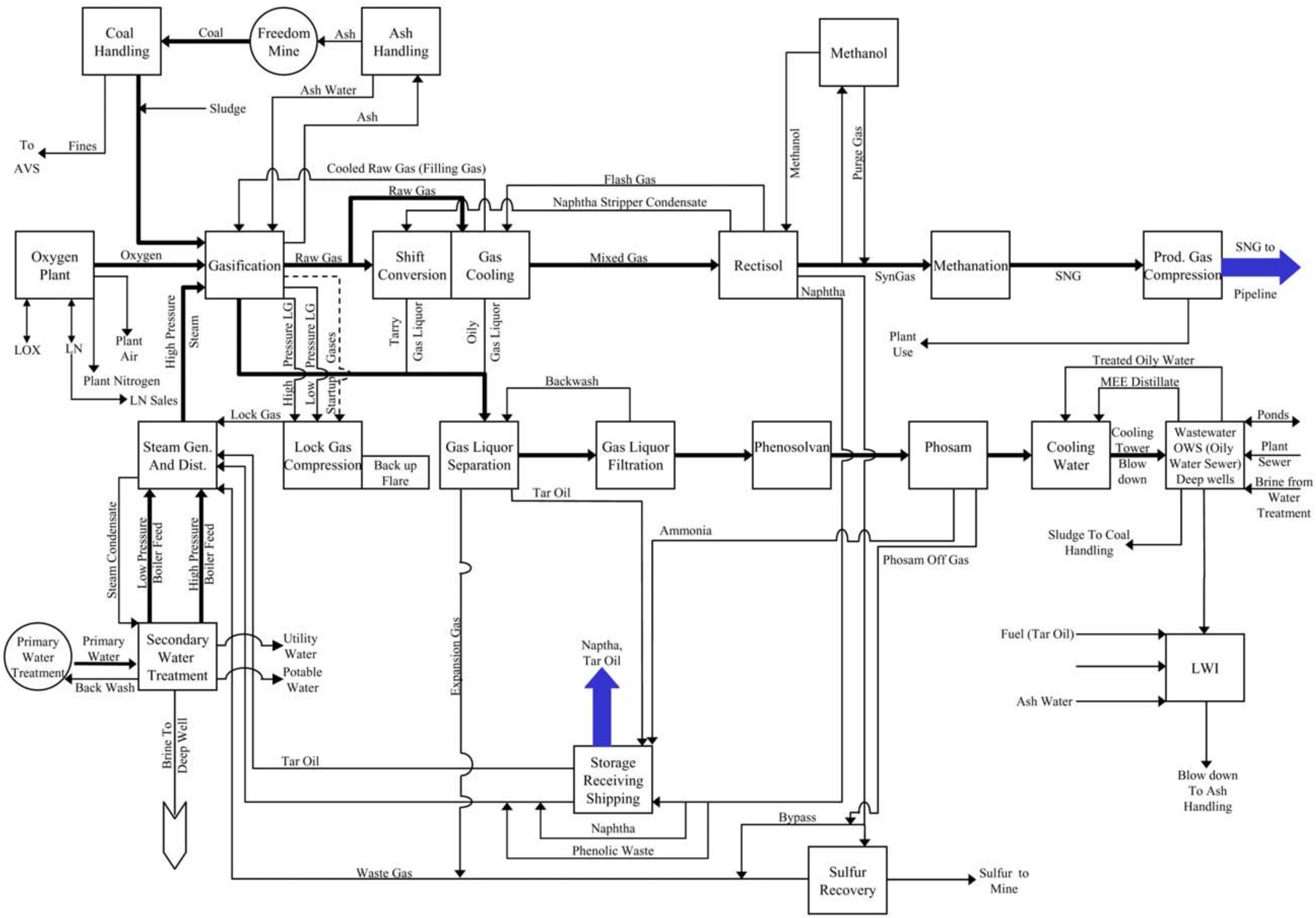


1) Addition of a Startup Flare in 1984
2) Removal of LWI in 1993
3) Phenol Purification unit added in 1990
4) Sulfur Recovery (Stretford) unit removed in 1994
5) Flue Gas Desulfurization unit added in 1997
6) Ammonia plant added in 1997
7) CO_2 Compression and Pipeline added in 2000
8) Wet Electrostatic Precipitator added in 2001

Appendix 3: Detailed Block Flow Diagram with Overlay



Appendix 4: Acronyms

ANG	American Natural Gas company
ASU	Air Separation Unit
AVS	Antelope Valley Station
BEPC	Basin Electric Power Cooperative
Btu	British Thermal Unit
DAF	Dissolved Air Floatation
DGC	Dakota Gasification Company
DOE	Department Of Energy
DoD	Department Of Defense
FE	Office of Fossil Energy
FGD	Flue Gas Desulfurization
GPSP	Great Plains Synfuels Plant
IGCC	Integrated Gasification Combined-Cycle
IPE	Isopropyl Ether
KBR	Kellogg, Brown and Root
LWI	Liquid Waste Incinerator
MEE	Multiple Effects Evaporator
MMSCFD	Million Standard Cubic Feet per Day
PMS	Plant Monitoring System
SGL	Stripped Gas Liquor

SNG	Synthetic Natural Gas
TMS	Technology & Management Services, Inc
TRIG	Transport Reactor Integrated Gasification
Wet ESP	Wet Electrostatic Precipitator

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Other Department of Energy Resources

Appendix 6: Acknowledgements

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