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The Weyburn CO_2 Monitoring Project – Economic modelling of CO_2 sequestration: Provisional report on the Great Plains Synfuels Plant (the CO_2 source).

Reservoir Geoscience Programme

Internal Report CR/02/019

BRITISH GEOLOGICAL SURVEY

INTERNAL REPORT CR/02/019

The Weyburn CO_2 Monitoring Project – Economic modelling of CO_2 sequestration: Provisional report on the Great Plains Synfuels Plant (the CO_2 source).

Dr. Nick Riley

Key words

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Front cover

Cover picture The Great Plains Synfuels Plant, North Dakota, USA (courtesy of the Dakota Gasification Company).

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Foreword

This provisional report is part of a series of studies being conducted by the British Geological Survey as part of the European team effort funded by the European Union to participate in the International Energy Agency's Weyburn CO_2 monitoring project. This international project, which also involves many non-EU researchers who are sponsored through the Petroleum Technology Research Centre (Canada) by various organisations and governments, seeks to understand the effectiveness of using enhanced oil recovery (EOR) as a means of sequestering CO_2. BGS also acknowledges support from the UK Department of Trade & Industry's Clean Coal Technology Programme. All sources used in this report are from the public domain.

Dr. Nick Riley, British Geological Survey, January 2002

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Summary

This report describes various aspects of the economics of a coal gasification plant, The Great Plains Synfuels Plant, N. Dakota, USA, which is the CO_2 source for an enhanced oil recovery operation being conducted at the Weyburn Field in Canada. Significant factors in the economics of the plant are political support at national and regional level, government underwriting of loans and financing, tax credits favouring domestic energy production, close proximity to lignite feedstock at a stable & low price, sharing of site facilities with other power generators, a regional market for bi-products- particularly fertiliser, forging long term gas supply contracts, ability to maintain a reliable supply of syngas, successfully hedging on gas price futures against price volatility, and switching interruptible gas production to bi-product production when the market is favourable. Sales of CO_2 to an oil company have only recently started, with sales of less than half the available CO_2 production expected to bring in net revenue of $15-18m/annum over the next 15 years. Future success of the plant will depend on natural gas prices, development of further bi-products and the ability to sell the remaining CO_2 to oil companies. The introduction of some form of carbon tax credit would also significantly enhance the plant's future viability.

1 Introduction

The use of CO_2 in enhanced oil recovery (EOR) has been conducted in N. America for several decades. A big stimulus for CO_2 EOR development was the Oil Windfall Tax introduced in the USA in 1981, which favoured EOR use in the USA's domestic oil fields. Unfortunately this EOR technique has used CO_2 sourced from natural accumulations (e.g. the Bravo Dome), which has resulted in CO_2 which otherwise have remained in the ground being exploited and has therefore increased CO_2 emissions to the atmosphere. If, as an alternative, the CO_2 can be sourced from industrial plant an opportunity is provided, not only to sell this CO_2 to an oil producer, but also to sequester a proportion of it underground as a bi-product of the EOR process and thus reduce emissions. In a fiscal/legislative environment where there are no financial penalties for emitting CO_2, EOR provides a commercially viable route for the sequestration of industrially produced CO_2.

Part of the strategy for reducing CO_2 emissions is to replace high carbon content fuels with low or zero carbon ones at the point of end use (an example is the "dash for gas" in UK electricity generation). Coal is a high carbon content fuel and it is undesirable from a CO_2 emission point of view to simply burn this type of fuel in a conventional power plant boiler. World coal reserves are however vast, with several hundred years supply of known recoverable reserves at present consumption rates. The challenge is therefore to utilise this important resource but in a cleaner way. The manufacture of synthetic low carbon fuels (and chemical bi-products) from coal is one strategy that is being sought. Synthetic fuels not only provide a mechanism for supplying low, or zero, emission fuels (e.g. methane, hydrogen) derived from fossil fuels (and waste or biomass), it also creates an opportunity to remove carbon relatively easily, as a pure stream of CO_2, as a normal part of the syngas cleaning process. This avoids the problem of removing CO_2 from the large volume of low CO_2 concentration flue gases emissions produced from a coal burning power plant.

This report focuses on the processes and economics of the Great Plains Synfuels Plant (GPSP). Although this plant is essentially based on gasifyer technology which is now several decades old; a modern synfuels plant would be built differently and at less expense; it still provides the only commercial example of synfuel manufacture linked to CO_2 sequestration. It is a foretaste of a new generation of synfuels plants now emerging (e.g. at Tampa) which will combine energy generation with petro- and agro-chemical production. Such plants are likely to succeed in the future as they can operate on a diverse feedstock of raw fuels (even waste) and switch production to a variety of synthetic fuels and chemical products as the market demands.

2 Location

The Great Plains Synfuels Plant (GPSP) is located in N. Dakota 8 miles north west of the town of Beulah (Figs. 1 & 2). It's prime activity and reason for construction is for the manufacture of synthetic natural gas (syngas) derived from lignite deposits supplied by the adjacent Freedom Mine. The GPSP has subsequently developed the production of a number of bi-products, of which fertiliser has been the most important, with CO_2 being the most recent bi-product to be marketed. The CO_2 is fed along a purpose built pipeline, 320km north to the Weyburn Field in Saskatchewan, Canada. CO_2 has been delivered to Weyburn since Sept 2000 as a means of enhancing oil recovery. The EU funded Weyburn Project seeks to look at the economics of the entire EOR operation. Because CO_2 injection at the field is still in its early stages it is premature to evaluate the EOR part of the economics. The present report concentrates on the economic development of the industrial source (GPSP) of the CO_2 up to the 1st January 2001 (the start date of the EU contract). All prices used are nominal and not adjusted for inflation.

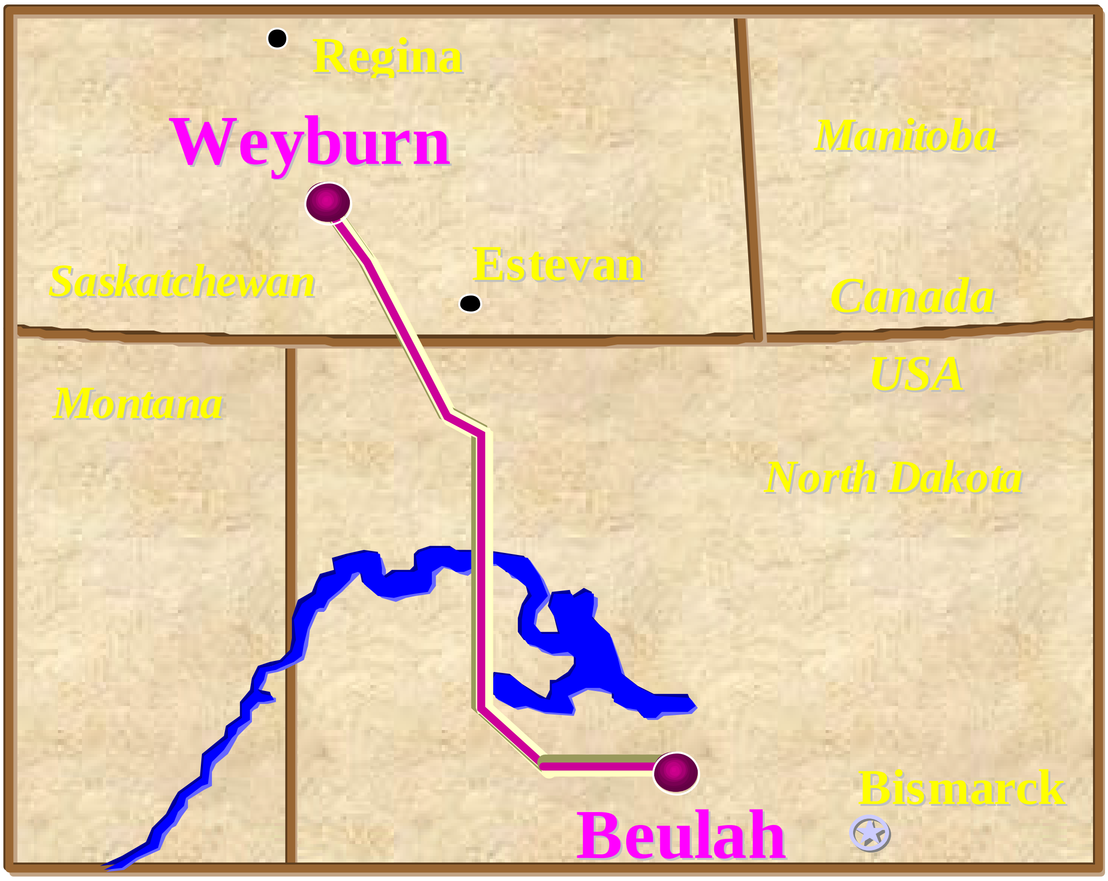


Figure 1: ***Location of the Great Plains Synfuels Plant (Beulah) and the Weyburn Field-linked by the CO_2 pipeline (courtesy of PTRC).***

Figure 2: ***The Great Plains Synfuels Plant (courtesy of the Dakota Gasification Company)***

3 Outline of the plant and the syngas process

The plant takes 16,200 tonnes/day of crushed (2x0.25 inch) lignite from the nearby Freedom Mine. Crushed coal is fed to 14 Lurgi dry bottom gasifiers. Steam and O_2 are injected causing high temperature partial combustion (1200^{o}C). The resultant gases are quenched and cooled to give tar oil, phenols, water (gas liquor). Raw synthesis gas is separated and shifted, using a cobalt molybdenum catalyst, to a H_2/CO ratio greater than 3:1 & fed to the Rectisol Unit. It is purified in a low temperature -95 to -70^{o}C methanol wash. This selectively removes naptha, sulphur. compounds and CO_2. The clean synthesis gas is then passed over a reduced nickel catalyst to produce CH_4 and H_2O. Daily production of 3050 tonnes of synthetic natural gas is mainly fed to consumers of the Dakota Gas Company, with a proportion (variable) used onsite for the manufacture of anhydrous ammonia. The Rectisol Unit produces 13000 tonnes/day of CO_2 (96%Mole) waste gas of which up to 5000 tonnes/day is delivered to Weyburn. The remaining production is available for other oil fields within reach of the pipeline.

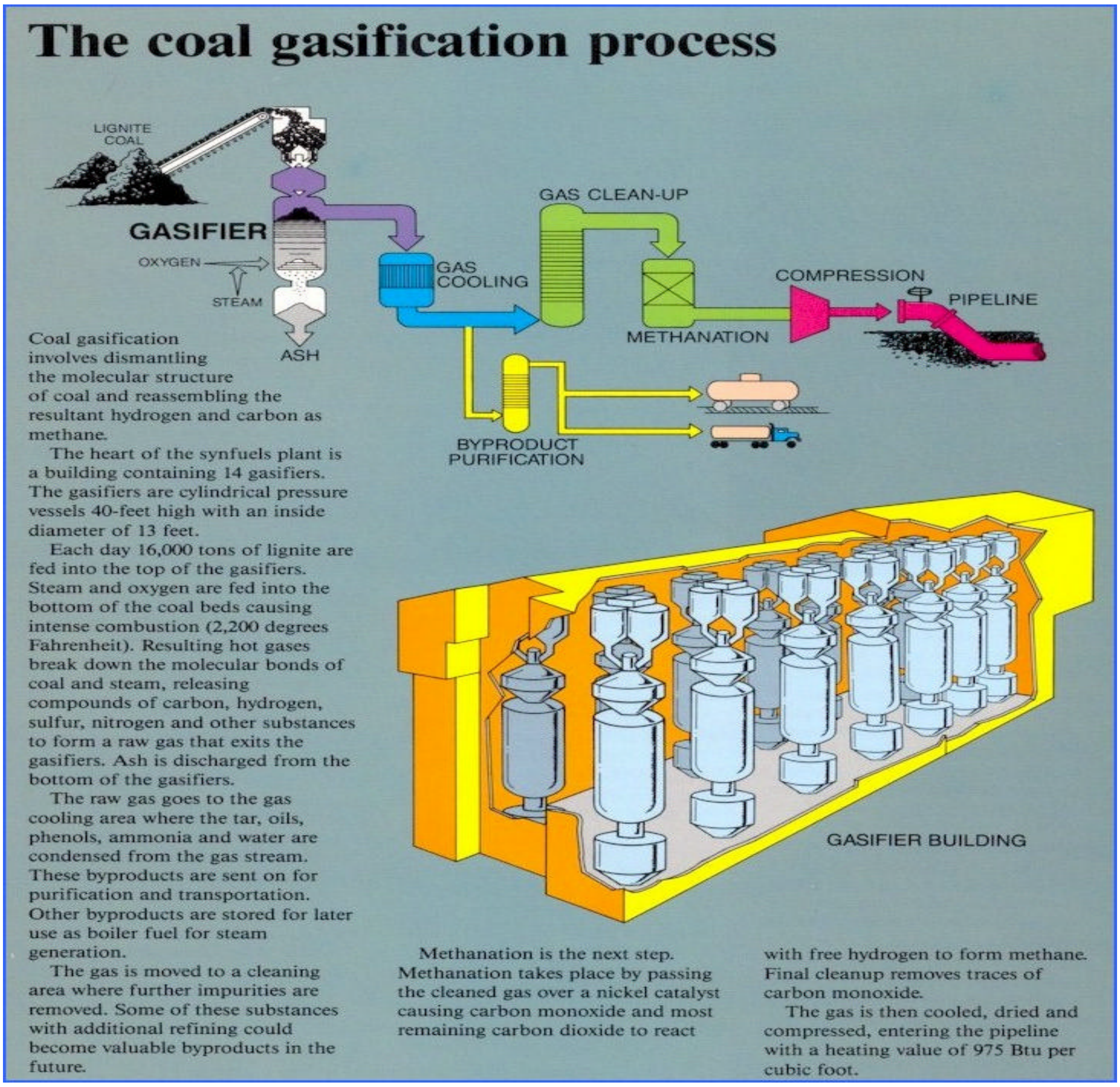


Figure 3 ***Diagram explaining the syngas process (courtesy of the Dakota Gasification Company)***

The Clean synthesis gas contains the following (Mole %) constituents; Hydrogen 61.8, Carbon monoxide 20.00, Methane 16.9, Nitrogen 0.25, Argon 0.45, Carbon dioxide 0.60. This demonstrates that the plant could be used for hydrogen production if required.

4 Bi-products

The plant has developed a number of bi-products and these have become an important part of the plant's economics, decreasing its exposure to volatile gas prices.

Biproduct capacities at Dec 2000 were as follows;

Ammonium sulphate (150kt)

Anhydrous ammonia (350kt)

Dephenolised cresylic acid & Tar oil cresylic acid (15kt)

Krypton & Xenon (3.1m litres)

Liquid nitrogen (91m litres)

Naptha (26.5m litres).

Phenol (15kt)

Carbon dioxide (40.2billion cu ft.)

4.1 THE CO_2 STREAM

The level of impurity in the CO_2 supplied from the GPSP is ideal for use in enhanced oil recovery. This is because 100% pure CO_2 is less effective as an EOR gas than slightly impure CO_2 (CO_2 dissolves more readily into oil when small impurities are present). The presence of H_2S as an impurity is also an advantage as this particular gas further enhances the ability of the injected CO_2 to mix with the oil. Since Weyburn already contains H_2S, so introducing this gas into the oil reservoir presents no additional problems. One disadvantage of the syngas source of CO_2 is the presence of mecaptans. These hydrocarbons have a strong odour and it only requires minute concentrations for the human nose to pick up the smell (they are deliberately added to natural gas supplies for this reason so that leaks can be detected). The CO_2 supply comprises the following gases (% by volume) CO_2 96%, H_2S 0.9%,CH_4 0.7%,C_2+hydrocarbons 2.3%, CO 0.1%,N_2 <300 ppmbv, O_2 <50 ppmbv, H_2O<20 ppmbv.

4.1.1 Price of CO_2

The net income from CO_2 supply (up to 5000 tonnes/day) over the 15-year contract for supply to PanCanadian is stated by DGC to be of the order $15-18m/annum. This gives an estimate of about 10 US cents net income to DGC per tonne of CO_2 supplied. It is difficult to estimate from these figures what the selling price of CO_2 delivered to PanCanadian is (this is a commercial secret), as cost recovery of the pipeline construction ($110m), plus running, maintenance and compression costs will all be included in the final price. Assuming that the CO_2 is sold at @$1 mscf then the price per tonne will be @$19. This is likely to be the upper price limit due to potential competition form natural CO_2 sources within Canada.

The pipeline has extra capacity and sections designed in anticipation of joining new supply spurs to the main pipeline. If future CO_2 contracts are won from other oil field operators then the net revenue for the remaining 8000tonnes/day CO_2 capacity would be far greater than that derived from the contract with PanCanadian to supply Weyburn (assuming that the deal with

PanCanadian provides the bottom line for covering the cost of the main pipeline and supplying the CO_2).

4.2 NON CO2 BI-PRODUCT MARKETS/USES

4.2.1 Fertilisers:

DGC produces roughly 10% of N. America's fertiliser requirements. For the industry as a whole, natural gas is the main ingredient in the manufacture of high nitrogen content fertilisers. This has resulted in volatility of fertiliser prices in line with gas price fluctuations (Chart 1). As DGC manufactures its own gas this volatility has allowed DGC to maximise revenue by switching some of its gas production to ammonia production at times when fertiliser prices have been high. Those manufacturers dependent on natural gas have to shut down production during high natural gas prices, and this effect further enhances the price of fertilisers. DGC's independence from having to use natural gas allows it to increase market share at these times as well as command a premium price. During the second half of 2000 40% of US fertiliser manufacturers closed production as a result of high natural gas prices. DGC produces 2 main fertiliser products, they are;

Anhydrous ammonia- used mainly as a fertiliser (or feedstock for manufacture of other fertilisers) but also as a refrigerant, this product is shipped in liquid form by rail or truck

Ammonium sulphate- Used as a fertiliser DGC have marketed this under the brand "Dak Sul 45". DGC distribute it to Canada and USA via trucks and railcars. Much of the ammonium sulphate is produced by DGC from an innovative form of sulphur scrubbing (as an alternative to using limestone).

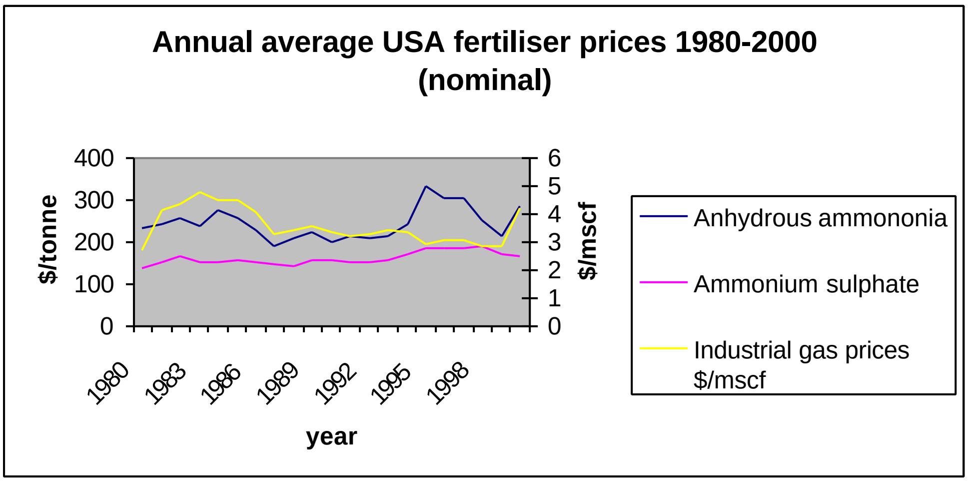


Figure 4 ***Note the close relationship of industrial gas prices (yellow) to fertiliser prices; except during the mid 90's when international ammonia based fertiliser shortages inflated prices.***

4.2.2 Petrochemicals:

Phenol- DGC is a relatively small supplier of phenol, with its main customer base in Canada. Phenol is used in resins for wood products, foundry moulds, paper and industrial coatings, and pipe insulation. Phenol prices have remained relatively stable but there is a risk of overcapacity in the USA

Cresylic acid- used for wire enamel solvent, making phenolic and epoxy resins, antioxidants and pesticides.

Naptha- used as a petrol blend stock, solvent and in benzene production.

4.2.3 Cryogenic and noble gases:

Liquid nitrogen- used as a cryogenic medium, enhanced oil recovery gas (only in deep oil fields) and in various chemical processes.

Krypton & Xenon- used in high intensity lighting, lasers and window insulation.

4.2.4 Other bi-products:

Other bi-product opportunities explored but so far not developed include aviation fuel, ethanol, methanol, hydrogen and synthetic diesel.

4.2.5 Bi-product revenues:

Revenues from bi-products in 2000 reached $78.2 million, about 30 percent of total sales revenue-they included;

Ammonium sulphate ($40.8m)

Anhydrous ammonia ($16.8m)

Dephenolised cresylic acid & Tar oil cresylic acid ($8.9m)

Krypton & Xenon ($1.6m)

Liquid nitrogen ($2m)

Naptha ($2.6)

Phenol ($5.5m).

5 The syngas market

In 2000 total marketed production of gas from both natural gas and oil wells in N. Dakota was 52426mmscf. Syngas supplied was 49190mmscf. North Dakota has no underground or LNG gas storage facility. Reliable and affordable gas supply has become increasingly important as demand has risen (particularly from industrial users). In 2000 total consumption by consumers was 36553mmscf of which, residential consumption was 10963, commercial 10787, industrial 14795. No significant amounts of gas were used for electrical generation. When the GPSP was conceived the plant's capacity exceeded consumption in N. Dakota, but in recent years consumption has outstripped syngas supply. Four pipeline companies take the snygas which is blended with natural gas before being delivered to consumers. Gas payment contracts with the pipeline companies are complex and an outline of their development can be found in the appendix of this report. According to Sinor Consultants Inc. during 2000 DGC broke even when natural gas prices reached $2.50 per dekatherm (1 dekatherm =1mmBtu or = ~1mscf), adding about $450,000 per month for each $0.10 increase per dekatherm. In 2000 DGC hedged more than half of its natural gas production at a price of nearly $2.80 per dekatherm. For this reason and because of price capping in the long term supply contracts to the pipeline companies, it became more profitable to switch interruptible syngas capacity into fertiliser manufacture, as natural gas prices rose steeply through the second half of 2000.

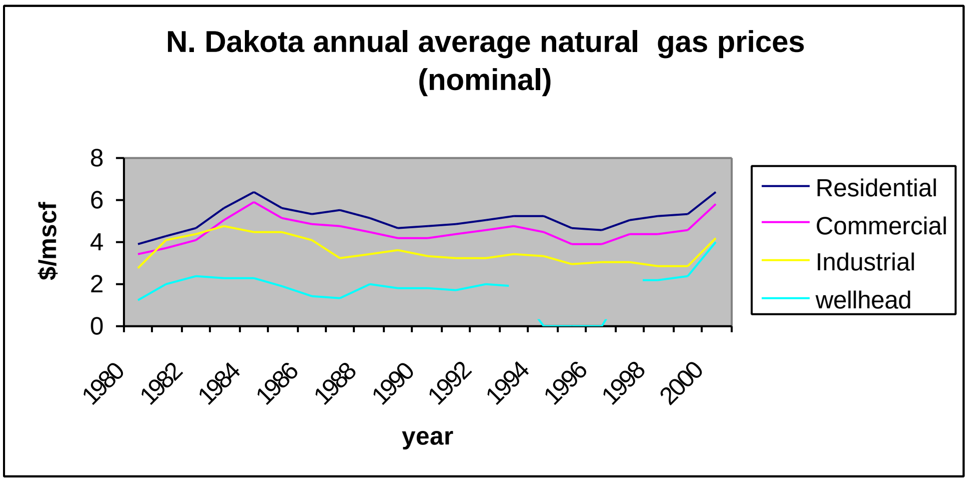
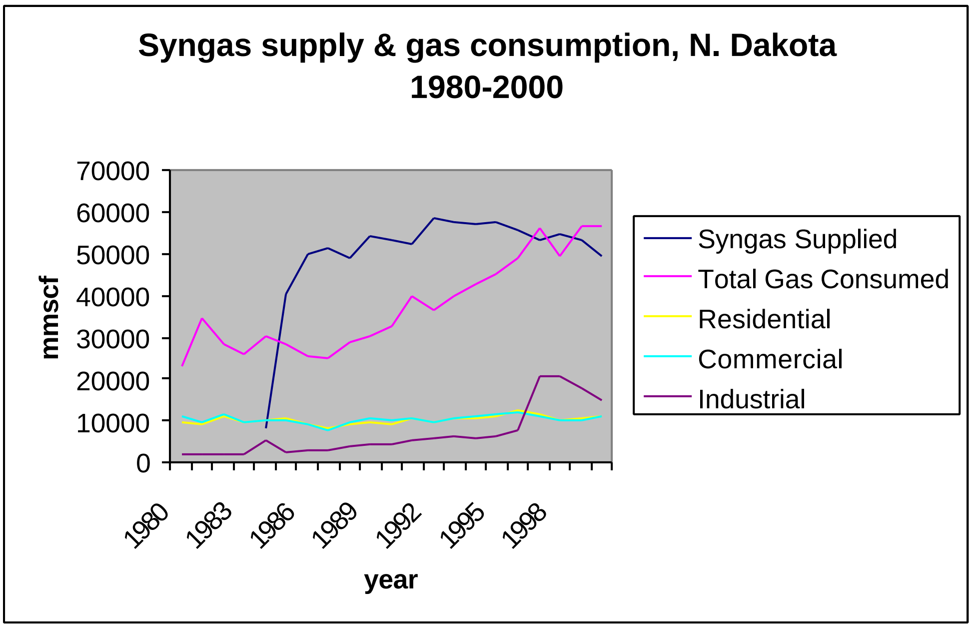


Figure 5 ***Delivered gas prices by sector in N. Dakota. Wellhead Price (data not available from 1995-7) represents the wellhead sales price, including charges for natural gas plant liquids subsequently removed from the gas, gathering and compression charges, and State production, severance, and/or similar charges. In 1999 Annual average sales for the DGC were @ $2.47 per dekatherm and in 2000 more than half of DGC's gas was delivered at a hedge price of $2.8 per dekatherm, spot price deliveries by DGC averaged at $8.74, giving a year average price for all gas delivered by DGC at @$3.81. At the end of 2000 gas prices rose steeply, reaching $13.75 at the Ventura Iowa trading hub.***



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6 Feedstock to the syngas plant

The GPSP is capable of taking waste products such as used car tyres and refinery sludges; these have been tried experimentally but the usual feedstock is lignite from the adjacent Freedom Mine. A strong factor in the economics is the very low cost of the lignite (even compared to average lignite costs in the USA- see Chart 4) and the close proximity of the GPSP to the mine (avoiding transportation costs).

6.1 FREEDOM MINE

The Freedom Mine is one of the 10th largest coal mines in the United States. It is an open cast strip mine Financed by Basin Electric, who also purchase most of the mine production (delivered to the adjacent Antelope Valley Power Plant and the GPSP by 2 mine mouth conveyors). It is owned and operated by The Coteau Properties Company, a subsidiary of North American Coal Corporation, Dallas. Typical lignite analysis from the mine is as follows:

Fixed Carbon 29.00%

Volatile Matter 27.00%

Moisture 36.80%

Ash 7.20%

Sodium as % of Ash 5.50%

Sulphur 0.70%

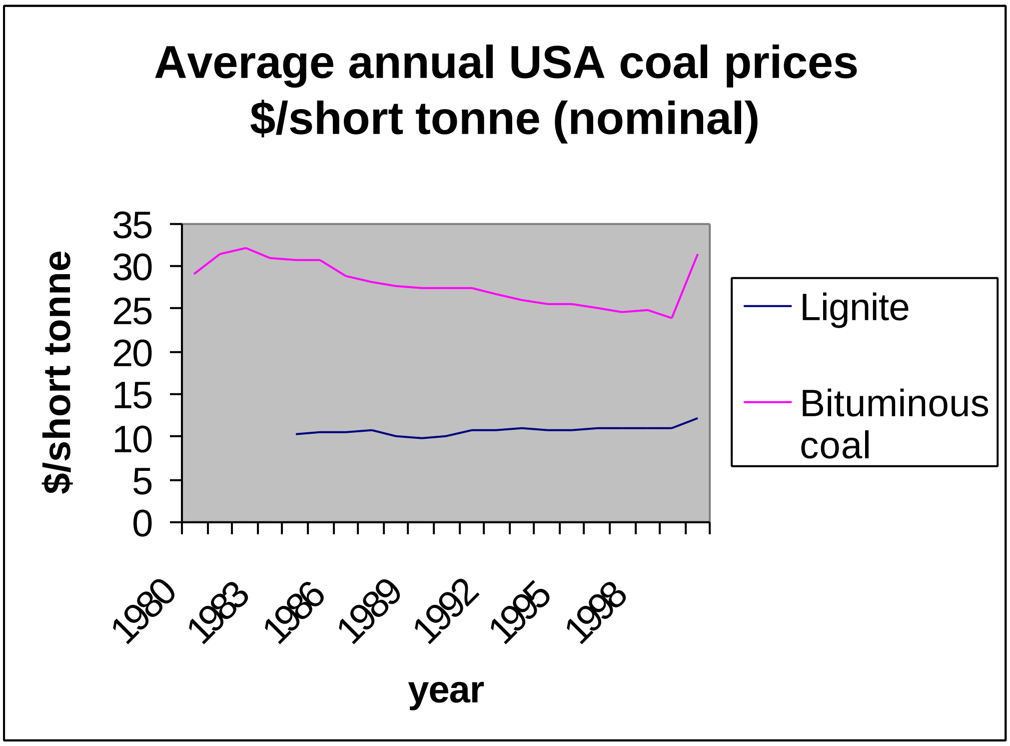
Btu/lb. 6,775

Size 2" x 0"

Ash Fusion Temp./Reducing Atmosphere: Initial 2280°F Fluid 2330°F. Recoverable Reserves 550 million tons. Annual Production 1999 – 16.3 million tons; 2000 – 16.2 million tons.

Figure 7 ***Lignite is removed by dragline at the Freedom Mine. The mine has won environmental awards for reinstating mined ground back to prairie (courtesy of Coteau Properties Co.)***

Lignite supplied to the adjacent Basin Electric Antelope Valley Station in 2000 comprised 5,734 (short tonnes), 6,554Btu/Ib, 0.65% sulphur by weight, 0.99 Ibs per MM Btu, Ash 9.32% by weight, average delivered cost was 66.8 cents per MMBtu, or $8.76 per short tonne. About one third of the coal mined at the Freedom Mine is supplied to the Great Plains Synfuels Plant for coal gasification and it is assumed that the lignite has similar analytical charactersitics. Lignite which is rejected by the synfuels plant (e.g. due to small matrix size & dust, unsuitable for the gasifyers) is re-directed to the power plant. Estimated benefits across the Basin Electric Co. and its member co-operatives arising from the cheap electricity (due largely to the acquisition of the lignite reserves and mine at low cost as part of the purchase of the Synfuels plant by Basin Electric in August 1988, as well as cost sharing between the synfuels plant and the power plant over water supply and site infrastructure) has been of the order of $0.5bn and certainly more than $30m year.



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7 Economic history

The oil crisis of the early 1970's exposed America to its dependency on imported fuel. The government therefore began to consider strategies to overcome any future oil crisis. Out of this was borne the vision of the Great Plains Synfuels Plant (GPSP). The vast lignite deposits of North Dakota could be transformed into versatile fuels, with reliable supply and stable cost, providing energy security for the Prairie States. The following is a summary of the main events, which cover the economic development of the plant from conception to December 2000.

1973 Estimate of plant cost -$500m

- experiments conducted to adapt the design of the Lurgi gasifiers to make them suitable for local lignite use-$2.

1975

- planned construction costs rise to $780m, with delay start date of early 1977.

1976

- plant construction plans scale down to first phase facility capable of delivering 125mmscf/d for an estimated cost of $600m, full capacity would therefore cost an estimated $1bn.

- Land prices adjacent to proposed site escalate to $10k/acre.

1978

- Subsidiaries of 5 major gas companies announce that they will form a consortium to build the nation's first coal gasification plant in North Dakota. Inflation has raised the price on phase 1 to $900m.
- Water supply project to gasification site and adjacent Antelope Valley Power Station commences.

1980

- US Gov. awards $240m loan guarantee to ensure first year of construction. Project cost estimates for phase 1 now $1bn.
- US Department of Energy (DOE) conditionally approves $1.5bn federal loan guarantee for the project.
- Press article (Newsweek) sponsored by the American Gas Association suggest costs will be $1.4bn.
- Great Plains Gasification Associates (GPGA) spend $9m toward site preparation.
- American Natural Resources Company (ANR) schedule $150m of work

1981

- Loan guarantee application is increased from $1.5bn to $1.8bn.
- Reagan administration approves conditional loan guarantee of $2.02bn for construction.
- construction starts August.
- 3000' water tunnel driven 180' below Lake Sakakawea as part of a 9 mile supply to the gasification plant and adjacent electric generating plant (Antelope Valley). Water supply completed to both plants in year after 3 years of construction.
- GPGA files settlement with the Federal Energy Regulatory Commission (FERC) at an agreed price of $6.75/dekatherm (1 dekatherm = 1 million Btu = ~1 thousand standard cubit feet mscf), but with future adjustments and price caps. Gas suppliers are allowed to pass costs onto consumers.

1982

- gas purchase agreement consolidated with pipeline companies agreeing to purchase a % each of production.
- bidding process starts to find purchasers of anhydrous ammonia and sulphur bi-products.
- All 14 gasifiers installed between July & November.

1983

- GPGA cash flow projections (March) suggest a loss of $840m in first 10 years of operation due to falling energy prices.

- April-plant construction 50% complete.
- December-the plant is 95% complete and employs permanent staff of 700.

1984

- April- first medium-Btu gas produced.
- General Accounting Office revises GPGA cash flow projections suggesting positive cash flow in first 10 years when tax benefits are included.
- May- first shipment of anhydrous ammonia.
- July- Antelope Valley Power Plant begins commercial operation.
- July- first high-Btu gas supplied to grid along 32 mile 24" pipeline to join northern border pipeline near Glen Ullin where syngas is blended with natural gas and then pumped on to north-central Iowa.
- Permanent workforce reaches 1000. GPGA announce that facilities cost $2bn (slightly within budget).
- July- plant fails to comply with sulphur emission legislation.
- Nov- peak production of 125mmscf/d achieved temporarily.
- GPGA changes cash flow projections to show a loss of $1.3bn in first 10 years due to continuing deterioration in energy prices. Under gas purchase agreements the initial price for SNG was set at $6.75 per dekatherm . The contract set a cap so that the price of SNG could not rise above the price of No.2 fuel oil. Original projections suggested that GPGA would be able to charge between $9-10 per dekatherm. But instead the price of No.2 fuel oil dropped. This suggested an operating loss of $1.3bn for the first 10 years or more of operation instead of $0.7bn profit.
- SFC board requests DOE to stretch out the repayment of $1.5bn conditional loan. The DOE extended the in service date of the plant from the end of 1984 to July 1985 to accommodate the new financial package for the GPGA. By mid July the SFC approved a tentative agreement in principle, or $720m of price supports, as well as restructuring of debt repayment through DOE. That package would have generated a price of $6.75 per dekatherm for syngas, compared to a market price at the time of between $2-3 per dekatherm, but on July 30th 1985 the Reagan Adminstration failed to adopt the deal. Pipeline companies then filed a law suite to declare a “get out” of 25 year contracts as the DOE would not guarantee a 25 year period of gas supply.
- With the syngas plant threatened with closure a study on conversion of the plant to making aviation fuel estimated that conversion costs would be $160m.
- Original design capacity of the syngas plant was to produce 20,000 equivalent barrels of oil per day.

1986

- In mid Jan 1986 Court rules that DOE have the right to foreclose on the mortgage of GPGA.
- US Gov. acquires plant and its assets (June 30) at a sheriff’s auction for $1bn. DOE forecasts positive cash flow to reach $200m by 1989.

1987

- DOE announce plans to sell plant. By end of year, 15 companies express interest in plant purchase of these Basin Electric were the most significant as they were concerned that if the

Syngas plant closed, or was operated by another owner, then their Antelope Valley Power plant adjacent to the syngas plant could be adversely affected.

- Great Plains Synfuels Plant had an obligation for $12m debt repayments on water treatment, rail and other facilities used jointly with Antelope Valley, also $17m per annum fixed costs paid by the American Natural Gas Company (ANG) now known as the American Natural Resources Company (ANR) for power supplied to the plant as well as estimates $8m increase in mining costs should ANG lose the synfuels plant coal purchase. The Basin Electric Co. had invested $1.5bn in the Antelope Valley Station and mine facilities. To cover this huge construction debt, Basin Electric was charging 5.6cents per kW to its members. It estimated that if the GSPSP closed the impact on Basin Electric would be @$37m per annum. Closure would release 90MW of capacity from Antelope Valley but it would have no market to sell it to.
- In Nov 87, Basin Electric calculated that if the crude oil price stayed above $15/barrel, at the current price paid by the pipeline companies of $3.75 per dekatherm (about 50% above market price) This meant generating positive cash flow of about $3m/month.
- The Beta Pipeline Co. of Texas reported to have bid $1.3bn for the plant- its interest was in switching the plant to making jet and car fuel ("aquafuel").

1988

- production tax credits were granted to the company in 1980 under the Crude Oil Windfall Profit Tax Act; GPSP was entitled to these credits.
- In 1988 based on a rate of $3 per 5.8m Btu would result in @$697 of production tax credits through to 2000 (the last year that the 1980 Act referred to). So a $300m bid by a company planning to use the available tax credits actually represented a net loss to the federal Government.
- The DOE insisted that any bidder also set up a reserve fund to deal with SO_2 problems from the plant as well as commitments to develop bi-products and maintain SNG products long term.
- In 1988 the General Accounting Office (GAO) made cash flow projections 1988-2001 to generate $6.9bn in total revenues with more than $6.6bn from gas and $122m in bi-products. It placed a theoretical value for the plant of $569m based on future net revenues. With production tax credits factored in for a new owner the government would need to be paid $1bn to realise a net gain of $569, according to the GAO.
- August- DOE selects Basin Electric as the successful bidder. The bid included:

Profit sharing-100% of gas plant's profits to go to DOE for first 14 months, then DGC for next 5 then DOE for next 10, then share for the last 5 years (profits were defined as the difference between gross revenues from syngas sales within contractually specified gas production costs and taxes).

A waiver of production tax credits (estimated at $590m) – these were later reinstated.

$70m cash for associated mining rights and equipment.

$15m cash for pipeline connecting gasification to the interstate pipeline.

$30m line of credit to Basin Electric's new subsidiary company (Dakota Gasification Company- DGC) that would own and operate the plant.

DGC to keep all revenues from bi-product sales (projected at $50m/year).

In the bid analysis DOE valued basin's bid at $594, about $13m more than Coastal's and more than £120m more than Mission's.

DGC took control on Nov 1 1988. As part of the deal DOE made several commitments including

leaving $15m in working capital at the plant

$30m trust fund for environmental improvement

$75m trust fund to cushion any economic shortfalls for the plant.

- with Basin having acquired the Freedom Mine, Basin Electric viewed that this acquisition would offset risk should the gasification plant fail.
- ANG had 822 employees, when DGC took over employees were reduced to 778.

1989

Month long average peaked at 159.9 mmscfd in April 1989. By year-end the production had increased to an average of 7% above the level of the plant's design capacity of 137.5mmscf/day, with production costs reduced 12% below projection. This was achieved by regularly operating 13 out of the 14 gasifyers. Original design had planned for only 12, with 1 on standby and 1 on maintenance. Coal quality also had an effect; high syngas production coincided with low sodium coal which presented fewer problems in the gasification process. Higher production also coincided with cooler months...due to better cooling water quality.

Dun & Bradstreet give the plant its first financial rating of 5A2 (same as the parent company Basin Electric) out of a possible highest rate of 5A1. ANG had never achieved a rating. The rating increased confidence in supplier and vendors and could assist in achieving more credit.

In 1989 bi-products included anhydrous ammonia, liquid nitrogen and sulphur. The DGC board approved $25m in capital projects. Investment of $4m was required for making and selling rare gas (krypton, xenon) and phenol. DGC reached 15-year supply agreement with Union Carbide Industrial Gases Inc (Now Praxair Ltd) for these gases. It also agreed to look at the potential for methanol production feasibility, but this was later abandoned because the pipeline companies would not allow diversion of methane for this purpose. Over the following years DGC would develop extensive pilot size solvent extraction and fractionation equipment and the analytical facilities to support bi-product development. These facilities were not used full time so DGC decided to make these services and facilities available outside the company. DGC also received certification to design, fabricate and repair pressure vessels and was able to generate revenue by offering this service to outside customers.

In the first 14months DGC earned nearly $31m in after tax profits of which DOE received $11m in revenue from DGC. @$4m of pre-tax revenue was from bi-products.

In July 1989 the price cap agreement changed from previous pegging. The DGC price cap was now based on the average cost of the highest 10% that each of the pipeline companies bought in the open market. For DGC this meant that the new price would be closer to the production cost price- the price paid was $3.14 per dekatherm. The pipeline companies tried to default on the contract complaining that the contract was formulated when the design output of the plant was 137.5mmscfd rather than 165mmscfd being produced through the efficiencies.

1990

- April- construction of phenol bi-product plant (investment of $20m) starts. Bi-product to be generated from the boiler fuel hydrocarbon stream.

- October- DGC file law-suite against the pipeline companies for $76m damages accusing them of grossly understating the market price of gas . Presenting evidence cost DGC $3m in legal fees/admin. The case was also costing $0.5m/month for DGC.
- Bi-product revenue for 1990 was $4.2m.

1991

- phenol production on stream.

1992

- By 1992 synfuels plant routinely gasifying coal at the rate of nearly 160mmscfd, well above the design rate of 137.5mmscfd. The workforce had also been reduced by nearly 30%.
- improved gasification and oxygen plant capacity.
- Installed larger, more efficient turbine drives for gas compression, allowing more product to be delivered into the pipeline.
- Improved equipment maintenance and operating procedures resulting in better availability of gasifyers.
- Installed new computer maintenance management system resulting in better planning, scheduling and completion of maintenance work.
- Increased life of methanation catalyst materials by better removal of sulphur in the feed gas.
- improved the gasifyer coal feed by better coal blending, screening and crushing.

1993

- Revenue from bi-products in 1993 was $16.9m.
- Health Department issues construction permit requiring DGC to install a scrubber to lower SO_2 emissions from the plant's main stack within 4 years. Estimated cost $90-100m.
- First cresylic acid sold (to UK company).

1994

- out of court settlement reached- it included:

-re-imbursement to DGC of $37m for past under payments for syngas and transportation. Pay DGC market price from Great Plains & make monthly payments to DGC over 7-year period. Demand payments amounted to more than $500m when adjusted for inflation over the period of 84 payments. However, once demand payments end the settlement meant DGC would receive only market prices for its gas for the remaining term of the gas purchase agreements, which finish in July 2009.

In a separate settlement DGC agreed to pay DOE $25m + interest over 7 years, continue the revenue sharing plan throughout the contract and allow DOE to eliminate the $75m trust fund set up at the time DGC purchased the plant in 1988.

- This settlement was contingent on the final approval by the FERC (Federal Energy Regulatory Commission). The settlement required that the pipeline companies pay DGC $3.7/dekatherm for its syngas until final approval of the agreement. The settlement spelt out that each pipeline company would be credited for it's above market payments against its future demand payment. This would cap the demand payments, which have a greater value over time, to be paid more quickly than expected. That covered the inflation-adjusted payments that DGC would receive in the next 7 years and reduce the overall sum the company would receive. Only the Natural Gas Pipeline Company got final FERC approval, the other 3 companies did not. As a result DGC received about 1/3 of its demand payments in less than a year. At that rate DGC projected that more than 80% of demand payments would be made by early 1997.

- Sulphur scrubber construction started.
- sulphur scrubber would require DGC to make more anhydrous ammonia raising its original production of 25000 tonnes per year. By early 1994 fertiliser prices had risen to $300 per ton, nearly double the price for the early 90's. Along with this potential business opportunity the company was watching natural gas prices continue falling to below $2/dekatherm (DGC' s production cost was about $3/dekatherm). That made anhydrous ammonia more valuable than natural gas, even when based on the lower fertiliser prices of the early 90's. Just to provide anhydrous ammonia for the scrubber required diverting 20% of raw syngas to produce about 1000 tons of anhydrous ammonia per day. DGC was able to raise a $12m grant and loan from the State of Dakota because of the benefit of the project to agriculture. Initially the cost of the fertiliser project was about $80m. DGC purchased an existing anhydrous ammonia plant from Fort Madison IA. This was projected to undercut the cost of installing a brand new plant (estimated $135m) and allow DGC to bring up production quickly whilst the market was favourable.

1995.

- June Construction begins on 1000 ton per day anhydrous ammonia facility.
- December- the FERC ruled that agreements with ANR, Tennessee and Transcontinental should be nullified.

1996

- By January, as a result of the FERC ruling the Synfuels Plant look threatened with closure. The ruling meant that DGC should sell its gas at a price = to the price index on the Gulf Coast plus 5%. This amounted to $1.68/dekatherm- about $1/dekatherm below the company’s cost to produce syngas. The FERC ruling also stated that companies were only obliged to purchase 137.5mmscf/day. Ruling also that the pipeline companies should reimburse $275m to the customer from "overcharges" over the previous 2.5 years. That money would come from DGC.
- DGC immediately launched an appeal. Its Task Force reported that the GPSP represented $500m/year to the USA economy and that the pipeline companies should pay a premium for the strategically reliable long-term gas supply from DGC. In Dec 1996 the FERC reversed its decision and approved the settlements.
- sulphur scrubber began operation. at a cost of nearly $100m, including the $30m trust fund set up by the DOE. Early operation of this world first facility using anhydrous ammonia conversion to ammonium sulphate proved unreliable at first. There was also an additional environmental problem created by fine particulates of ammonium sulphate escaping from the scrubber. An additional $8m was invested by the company to improve reliability, but the plume problem was not solved. The scrubber did manage to reduce sulphur emissions by 93% enabling the plant to fall in line with the 1993 state permit.

1997

- January- relocated anhydrous ammonia plant and new scrubber become operational. Due to the severe winter of 96/7, plus the need to provide more engineering and construction than originally planned installation of the anhydrous ammonia plant was delayed and significantly above budget.

- DGC had been leasing 100 railcars for bi-product shipments. In 1997 DGC decided to purchase another 300 railcars (200 tank cars for anhydrous ammonia and 100 hopper cars for ammonium sulphate). For financial reasons the railcars were sold and leased back.
- Because the appeal process took nearly a year DGC saw its expected benefits dissipating as the settlement issue dragged. By Feb 1997 DGC had received 75% of its demand payments. Instead of $72m annually over the next 7 years DGC would now only receive about $30m a year through 2002 and then $18m a year for the final 2 years of the settlement period. This situation stimulated DGC to develop more bi-products.
- company receives a violation notice about sulphur and particulate emissions from the stack. In order to avoid $1.3m fine DGC plan to invest $35m to reduce emissions by installing a wet electrostatic precipitator. Also $5m set aside to address odour problem from makeup water in the plants cooling towers by installing an air stripper.
- July 15th - 15-year contract signed with PanCanadian to supply CO_2 to Weyburn Field. DGC to spend $110m to build pipeline and compressor and receive $15m-18m in net revenue from PanCanadian when supply starts. Subsidiary company Souris Valley Pipeline Ltd. was formed to operate the 35miles in Canada, with DGC operating the USA portion of the pipeline.
- 10-year property tax exemption granted by N Dakota legislator to assist financing (worth $1.4m). The company approached the federal government about using production tax credits for the 4-year period remaining until that law expires. The federal government agreed to let Dakota Gasification use the tax credits but required that the proceeds only be used to finance two projects, the carbon dioxide pipeline project and an emissions reduction project. The agreement had a repayment provision that would return all of the money lost to the US Treasury back to the federal government if the project is profitable in the future.
- In order to realise an economic gain from the production tax credits, DGC would have to sell the synfuels plant to a separate company that can effectively use the tax credits. However, DGC would continue to operate the plant as the operating agent of the investing company. In 4 years DGC will have an option to repurchase the plant at its fair market value. DGC never followed through on the sale of the tax credits. With natural gas prices rebounding in 2000, the economic benefits of completing the transaction changed and Basin & DGC boards decided not to proceed.

1998

- Consent agreement approved by the North Dakota district court required DGC to pay $162,500 initially and invest at least $487,500 on another project to reduce odours. The Health Department suspended or dismissed $425,000 net of a total of $625,000 in penalties. DGC ordered to meet further specific conditions in the consent agreement to avoid the remaining penalties.

1999

- Annual average sales @ $2.47 per dekatherm.
- June 1999 pipeline construction starts.
- DGC employees achieve more than $20 million in savings in 1999 compared to 1998, without jeopardising the reliability of the Synfuels Plant.

- Natural gas prices strengthened through the end of 1999. However, like other commodities, natural gas goes through market pricing cycles. To achieve more financial stability, DGC employed a financial transaction called hedging. Through hedging, DGC is able to ensure a price for a portion of its natural gas, foregoing the benefits of high prices but avoiding the revenue drop when prices fall. In 1999 hedging activities produced $3.5 million for the company.
- Gross revenue for DGC amounted to $201.9 million. Of this total, $139.2 million came from the natural gas sales and $62.7 million resulted from selling bi-products and other miscellaneous sources. DGC's expenses totalled $212.2 million in 1999. The company incurred a net loss of $6.8 million after interest and other income, interest expense and income tax benefits.

2000

- According to Sinor Consultants Inc. during 2000 DGC broke even when natural gas prices reached $2.50 per dekatherm, adding about $450,000 per month for each $0.10 increase per dekatherm.
- In 2000 DGC hedged more than half of its natural gas production at a price of nearly $2.80 per dekatherm.
- Sept 14 - first CO_2 enters pipeline to Weyburn. . That meant that DGC would receive $15 to $18 million per year in net income over the 15 year contract period with PanCanadian.
- Oct 12 -operating permit received from North Dakota Health Dept. re- emissions from stack and odour from steam condensers. Both projects to resolve these problems were on budget and ahead of schedule. DGC expects them to be completed well ahead of their compliance dates: June 1, 2003, for the Wet Electrostatic Precipitator (WESP) and December 31, 2002, for the odour control project.
- Operating costs reduced by $1m per month.
- DGC collected record revenues of $258.2 million and created a positive financial turnaround of more than $22 million. The company recorded a net income of $15.4 million in 2000 compared with a net loss of $6.8 million in 1999.
- Revenues from bi-products in 2000 reached $78.2 million, about 30 percent of total sales revenue they included;

Ammonium sulphate ($40.8m)

Anhydrous ammonia ($16.8m)

Dephenolised cresylic acid & Tar oil cresylic acid ($8.9m)

Krypton & Xenon ($1.6m)

Liquid nitrogen ($2m)

Naptha ($2.6)

Phenol ($5.5m)

- Natural gas prices were strong during 2000 hitting $13.75 per dekatherm on the cash market in late December at the Ventura, Iowa, trading hub. On the spot market, DGC sold natural gas at an average of $8.74 per dekatherm and received a year average of $3.81 per dekatherm for its natural gas, compared with the previous annual average of $2.47 per dekatherm. Strong fertiliser prices (anhydrous ammonia approaching $400/tonne by year end) also contributed to the record profits. But at times, natural gas prices rose high enough for the company cut back on its production of anhydrous ammonia to gain even more revenue from natural gas. That flexibility provided additional benefits for DGC.

- As a rule of thumb every $ increase in natural gas prices increases the price of anhydrous ammonia by $34/tonne.
- Although the pipeline was completed within budget and early technical problems arose in late 2000 involving odour, compressors and pipeline valves.

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