

CO₂ UNDERGROUND STORAGE COSTS AS EXPERIENCED AT SLEIPNER AND WEYBURN

Tore A. Torp¹ & Ken R. Brown^{2*}

¹Statoil Research Centre, NO-7005 Trondheim, Norway

²Petroleum Technology Research Centre (PTRC), Regina, Canada S4S 0A2.

ABSTRACT

Two major industrial undertakings – at Sleipner and Weyburn - show the technical feasibility of storing CO₂ in underground geological formations in large volumes. Their scale makes the investment and operational costs they have experienced of interest to a wider audience.

Together they cover a wide set of parameters:

Sleipner is offshore in the North Sea - Weyburn is onshore on the plains of Mid-West Canada.

Sleipner stores CO₂ in a deep saltwater formation – Weyburn is an Enhanced Oil Recovery project.

Sleipner injects by one horizontal injection well – Weyburn uses both horizontal and vertical wells.

Sleipner gets the CO₂ from natural gas produced on-the-spot – Weyburn transports CO₂ by a 330 km pipeline from a coal gasifier in the USA.

Sleipner has minimal impurities – Weyburn co-injects H₂S; a well-known Canadian procedure.

This paper highlights the extra costs associated with the CO₂ injection for storage purposes only. The design and operational considerations for both projects are only summarized, since they have been reported previously. In both projects the extra equipment for the CO₂ injection/storage was part of a large industrial development project, so the costs reported herein could not be very detailed. The reported costs for the two projects are very difficult to compare since the situations were so different.

SLEIPNER AND WEYBURN – TWO WORLD'S FIRSTS

The Sleipner natural gas field was the first to re-inject CO₂ to avoid emitting it to the atmosphere out of concern for climate change. Many gas fields worldwide have for decades removed CO₂ from the produced natural gas to be able to meet sales specifications– as Sleipner does. The growing international concerns over climate change and - in Norway - the CO₂ tax motivated by this, give commercial oil and gas field operations new framework conditions.

The Weyburn oil field was the first Enhanced Oil Recovery (EOR) project to rely entirely on anthropogenically produced CO₂, to obtain extensive baseline data sets before commencing injection operations, and to use these datasets to study the potential for significant storage of CO₂ beyond that required for commercial EOR [4]. Dozens of fields in the USA, Canada, Turkey and Hungary have used CO₂ for EOR, but have always tried to minimize the ratio of injected CO₂ over the incremental oil produced without considering additional storage potential. These projects have been designed for the optimal recovery of oil, but provide CO₂ storage as a bonus.

This paper will summarize the injection planning, the equipment installed to store the CO₂, and document the extra costs incurred for the CO₂ storage in the two projects. All costs are given in U S dollars (USD).

THE SLEIPNER FIELD AND ITS CO₂ SOURCE

The Sleipner offshore gas field is situated in the very centre of the North Sea in 80 – 100 meters water depth, and is operated by Statoil on behalf of ExxonMobil, Hydro, Total and the Norwegian state. The planning of the CO₂ handling and injection is described in detail by Baklid et al [1]. The Sleipner West part started production in 1996 and is expected to produce for 25 years. This natural gas contains around 9 % CO₂ from the reservoir some 2500 meter below sea level. The CO₂ content is unusual for most gas fields in the Norwegian sector of the North Sea. To

*Corresponding author: Tel. (403) 208-5577, Fax (403) 208-4882, Email: ken.brown@browngsc.com

meet the sales and pipeline specifications of a maximum 2.5 % CO₂ in the gas leaving the platform, the capture process was installed on the Sleipner T (treatment) platform at the field centre (See Figure 1 below).

The process selected for capturing the CO₂ was the use of an amine. This is a well-established process for this purpose, but it was the first time for the process to be packed together on an offshore platform. It consists of two absorption contact towers, each 4 meters wide by 20 meters high and weighing 240 metric tonnes each. In addition an amine regeneration facility was needed. After considerable process redesign and operational adjustments the process is now operating as specified. This capture part is not discussed further in this paper.

The captured CO₂ is then compressed and injected into what is called the “Utsira” formation. It is a vast aquifer - a salt water filled sand body 400 km long North-South, 50-100 km wide and 50-250 m thick at a depth of around 1000 m below the sea bottom (see Figure 2 below).

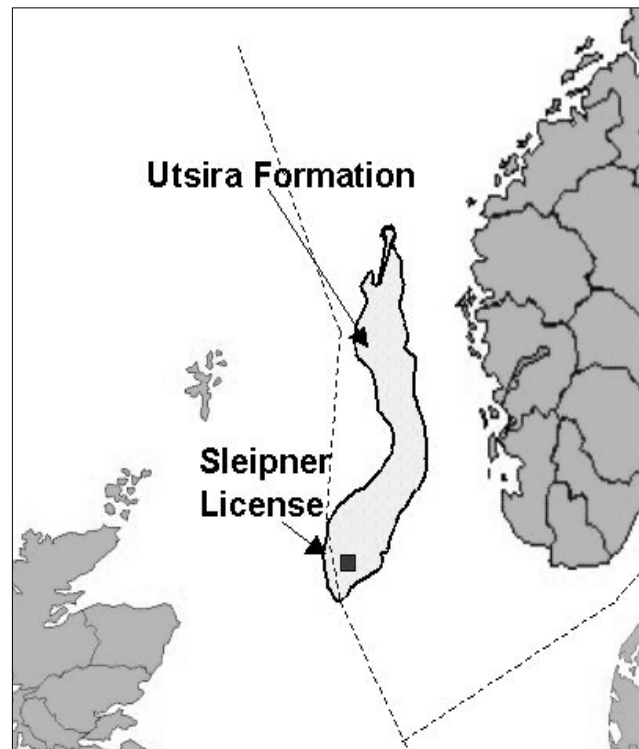
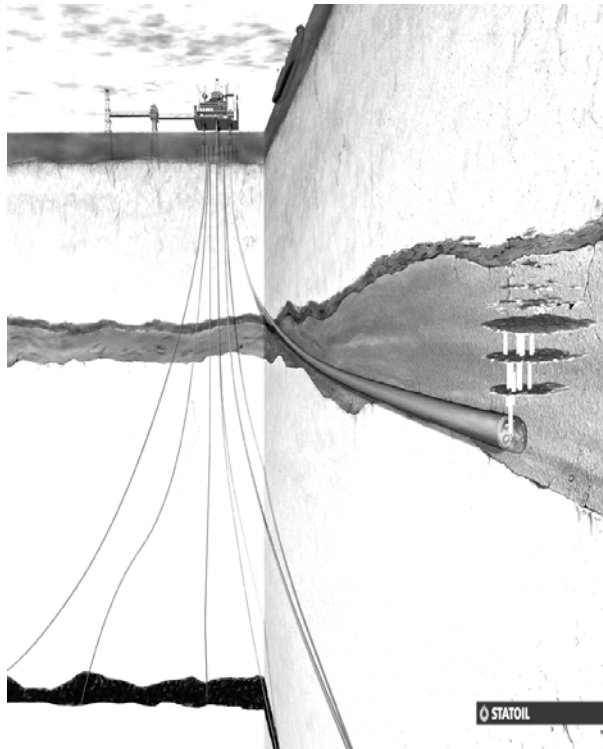


Figure 1: The Sleipner field with CO₂ injection (Statoil) **Figure 2:** The North Sea and the Utsira formation (Statoil)

Sleipner Data and Sample Collections and Injection Preparation Studies

The engineers planning the Sleipner West development searched for alternatives for handling of the amount of CO₂ expected over the field’s lifetime, 25 Mt CO₂ over 25 years.

One alternative was to emit it to the atmosphere and pay the CO₂ tax, around 320 NOK/t (40 USD/t at the actual rate 8 NOK/USD). That would increase the total Norwegian CO₂ emissions at the time by 3%. Another option was to use it for EOR – Enhanced Oil Recovery in a nearby field. No field was found suitable in size or timing to fit the Sleipner production rate; nor was recycling in the Sleipner gas-condensate reservoir found acceptable. The only alternative left, other than paying the tax, was underground injection in an aquifer - a separate sand body filled with salt water situated right below the Sleipner field (the “Utsira” formation). Before injection design could be finalized it had to be found suitable and safe to store the 25 Mt CO₂.

During field development preparations in 1993-94, the possible storage reservoir was mapped by 3D seismic, wells were logged and a core was taken from the reservoir sand. Water sampling was tried, but failed repeatedly. Trying to extract water from loose unconsolidated sand, like the “Utsira” easily collects only drilling fluids and sand.

To estimate the behaviour and spread of the CO₂ in the “Utsira” a reservoir simulation was performed. The CO₂ at 1000 m depth would be a supercritical (dense) phase with density around 0.7 and slightly buoyant. It was expected to rise to the top of the Utsira sand, be blocked by the several hundred meters of thick shales above, and then spread laterally. Since the “Utsira” is so highly permeable and vast, no pressure build up was expected during the 25 years production life. The concern was whether the slightly corrosive CO₂ would reach the production wells below the Sleipner platforms. By drilling a highly deviated injection well reaching nearly 4 km away this could be avoided. The conclusion was that the injection in “Utsira” would be feasible and safe. More details are given by Baklid et al [1].

The behaviour of the injected CO₂ over the years since the injection commenced in October 1996 has been carefully followed up through the SACS –Saline Aquifer CO₂ Storage project; an overview of which was given by Torp&Gale [2]. Another core was taken from the cap rock. The geology of the greater Sleipner region was mapped. Geochemistry studied, in laboratories, the possible chemical reactions and their rates between the Utsira sand and reservoir water as well as the cap rock shales with injected CO₂. The spread of the CO₂ has been monitored by repeated 3D (“4D”) seismic and matched with elaborate reservoir simulations. The SACS work was done by six European geo-scientific institutions and financially supported by six energy companies and the European Commission. All results have been published in “SACS Best Practice Manual” [3].

The monitoring (4D seismic and gravimetry) and studies of long-term behaviour (buoyancy flow, dissolution in water and geochemical reactions) is continuing, now under the project name CO2STORE. The participation from the SACS project has been enlarged with more European geo-scientific institutions, with power companies and with continued support by the European Commission. Also, it is planned that these results will be published.

SLEIPNER MARGINAL STORAGE COSTS

Before injection started, the storage formation and expected CO₂ behaviour was studied. The extra installations needed to handle the CO₂ coming from the capture unit were:

- compressor trains including gas turbine drives, and
- an injection well.

Extra operational cost elements, still continuing, are natural gas fuel for driving the compression and some marginal operation and maintenance manpower.

Sleipner Costs for Site Characterization

The data and sample gathering and reservoir simulations done before Sleipner CO₂ injection started, were all integrated into the much larger operations of preparing the whole field development. The extra marginal costs can therefore not be found exactly, only estimated. This results in these extra costs:

- Seismic 3D (based on costs of seismic surveys later)	3.2 MNOK (0.4 million USD)
- Coring “Utsira” sand, and well logs	7.2 -- “ -- (0.9 ---- “ ----)
- Coring the cap rock shales:	4.0 -- “ -- (0.5 ---- “ ----)
- Reservoir simulations (Estimate 6 person months):	<u>0.8 -- “ -- (0.1 ---- “ ----)</u>
Preparation works total	<u>15.2 -- “ -- (1.9 ---- “ ----)</u>

The Sleipner CO₂ Compressor Train and Gas Turbine Drive

The CO₂ was to be delivered from the amine capture process saturated by water at slightly above one atmosphere (1bar pressure) and needed to be compressed before injection through the well and into the “Utsira”. There were three main options, as a liquid, as gas and liquid two-phase, or as dense (supercritical) fluid. The main concern was to avoid hydrate formation and an overly complicated process control system, as well as an ability to take the CO₂ delivered at any time. Whether the rate was to be small or full, the control system should handle it. The pros and cons and chosen solution are described by Baklid et al [1].

The CO₂ is compressed in stages to 80 bars and cooled to about 40 degrees Celsius before entering the wellhead. It is then in the supercritical state – in many ways behaving as a liquid - with density very dependent on the temperature. With this, a hydrostatic column is formed in the well. For each compression stage water is knocked out at 30 degrees Celsius. Since the ability to dissolve water is lower at 32 bar (third stage) than at the wellhead, there is no free water at the wellhead therefore limiting any corrosion and hydrate formation. To be able to handle 1 Mt CO₂ per year, four parallel units were needed. Each unit has a fluid knockout drum, a compressor, a cooler and a gas turbine driver.

Again the compressor train with its gas turbine drive was designed and installed as part of the much larger operations of preparing the whole field development. The extra marginal costs can therefore not be found exactly, and can only be estimated. This results in these estimated extra costs:

Compressor train (4 units): 630 MNOK (79 million USD)

The Sleipner CO₂ Injection Well

As mentioned above a highly deviated well was needed to get the CO₂ plume into the “Utsira” formation and “away” from the production wells which are drilled from the Sleipner A platform. It has a total length of 3752 m and ends at 1163 m vertical depth counted from the drilling deck. Its terminal inclination is 83 degrees. Its tubing is made of 25% Chromium duplex steel to be on the safe side for corrosion, otherwise the well is of a standard injection design. More details are given by Baklid et al [1].

The challenge in drilling and completion of this CO₂ injection well was its small radius, caused by the shallow depth. Starting from the vertical at the drilling deck it needed to reach 83 degrees deviation over a short distance to terminate in the lower part of the “Utsira” formation.

The cost of drilling and completion of this CO₂ injection well is estimated at:

Injection well: 120.0 MNOK (15 million USD)

Sleipner Operational Costs

Since the CO₂ compressors and the injection well are part of a large integrated operation, identifiable extra storage costs are limited to marginal fuel consumption for the gas turbines driving the compressors and the CO₂ tax paid for the compressor fuel exhaust.

Natural gas consumption is estimated at 4 000 Sm³/t CO₂. Since the Sleipner field itself produces the natural gas, costs are calculated as gross sales price on the shore terminal minus transport fee in the pipeline to shore.

The cost of operational personnel and maintenance are very marginal.

Operational costs (fuel and CO₂ tax on exhaust): 54 MNOK (7 million USD) per year.

THE WEYBURN FIELD AND ITS CO₂ SOURCE

The Weyburn Oilfield is one of several large oilfields that lie along the northern edge of the Williston Basin, which extends from the northern United States into southern Canada (see Figure 3). The oilfield, operated by EnCana Corporation of Calgary, Alberta, Canada, is located 130 km (80 miles) SE of Regina, Saskatchewan, Canada. Medium gravity crude oil has been produced from this field since 1954 from the Midale beds of Mississippian age (see Figure 4).

The initial storage cost for CO₂ in the Weyburn field is complicated by the presence of the previous commercial EOR project, which included injection wells, modified production facilities, recycle equipment, and the value of additional oil production. Enhanced storage costs, beyond the EOR project, are essentially the cost of the incoming CO₂ plus a small operational expense for injection wells. The incoming CO₂ cost is currently a commercial, confidential contract between Dakota Gasification Company (DGC) and EnCana, but sufficient public domain information is available to accurately estimate the cost. The following analysis presents this information and provides additional information on modelling resources that are available for other projects.

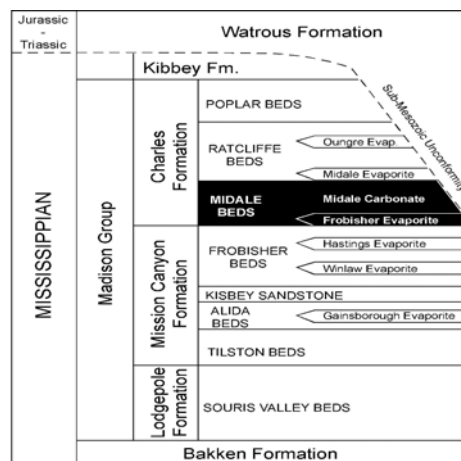
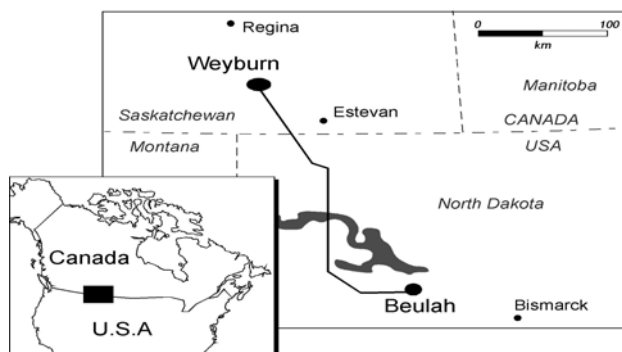


Figure 3: Pipeline route and oilfield location (PTRC). **Figure 4:** Stratigraphic column for Weyburn

Dakota Gasification Company Plant Facilities and Compression Equipment

The plant facilities and the compression equipment are described in detail in a previous paper [7] presented at GHGT-4. In summary the installed plant equipment consists of two Borsig compressors rated at 19,500 horsepower each and all their auxiliary piping systems. The pipeline and all its operating conditions are described in detail in the Canadian National Energy Board Approval [6]. The pipeline is 14 inch (355 mm) from the DGC Plant to the Tioga junction in North Dakota and is 12 inch (305 mm) the rest of the way to Weyburn. It operates at up to 20.4 MPa (2964 psi) to ensure delivery of the supercritical CO₂ to Weyburn at a pressure exceeding the 15 MPa (2175 psi) required for direct injection into the wells. The pipeline is expected to transport 350 BCF over the 15-year term of the contract with the Weyburn oilfield owners [7].

The entire DGC project, including plant, compression, and pipeline costs was \$100 million USD [8]. The plant and compression costs were 50% of the total [9]. Due to the nature of the project and the status of DGC's parent company (Basin Electric) as a utility, the project was regulated by the U.S. Federal Energy and Regulatory Commission to have a rate of return of 12.5%. This means that there is a fixed yearly demand payment based on the capital cost and an allowable rate of return. There is also an operational or variable payment based on operational costs of actual deliveries plus a rate of return.

Weyburn CO₂ Injection Facilities

The CO₂ injection facilities needed for enhanced storage already existed for the EOR project. This includes a field distribution system, measurement satellites, and short local pipelines to the injection wells [5]. Initial capital costs for this system are included in the EOR project. Initial operating costs for this system, which are actually borne by the EOR project, are estimated to be \$270,000 USD/year based on normal operation and maintenance expenses for the 19 patterns in the initial injection system.

The IEA GHG Weyburn CO₂ Monitoring and Storage Project

To develop confidence in the geological storage of CO₂ as a safe and environmentally acceptable mitigation option, it is necessary to provide sound scientific information that CO₂ injected into reservoirs can be stored for geological timescales. The IEA GHG Weyburn CO₂ Monitoring and Storage Project [4], a 27 million USD research project, addresses CO₂ storage occurring in conjunction with economic CO₂ enhanced oil recovery (EOR) operations. It commenced prior to initial injection and obtained seismic and other datasets that provide baseline information.

Phase 1 of the IEA GHG Weyburn CO₂ Monitoring and Storage Project was completed in June of 2004. Results to date show strong support for both the feasibility and the safety of geological CO₂ storage. Clearly, CO₂ storage can safely take place without impacting EOR operations. In fact, economic studies performed as part of this Project [4] demonstrated that implementation of incentives used to motivate additional CO₂ storage, beyond that normally associated with EOR, could also ultimately result in additional oil recovery.

Phase 2 is a new program that will build on the successes of Phase 1 to address research and demonstration opportunities that have been identified in Phase 1. Phase 2 results will be useful for those interested in subsurface properties and processes involving CO₂ rich fluids, as well as those involved in assessing the reliability of and requirements for establishing CO₂ storage projects.

None of the research costs for Phase 1 or Phase 2 are included in the following analysis as they are not part of the required operational costs for enhanced storage.

WEYBURN MARGINAL CO₂ COST

Weyburn CO₂ Supply Costs

Based on the public information summarized in 4.1 and 4.2 above, the initial annual CO₂ delivery cost for enhanced storage is estimated at:

Return on Capital – 12.5% of \$100 million	\$12,500,000
DGC operating expense <i>20% of plant capital [10], \$500,000 USD/year pipeline, 12.5% return</i>	\$11,812,500
Weyburn operating expense (see 4.2)	\$270,000
First year CO ₂ delivery (350 BCF averaged over 15 years)	1,226,400 tonnes

The storage of CO₂ in Weyburn in the initial year is therefore estimated at \$20.04 /tonne (\$1.05/mscf).

Weyburn Investments

As stated in section 4.2, the facilities to inject CO₂ in the Weyburn field for enhanced storage already exist as part of the continuing EOR project.

To evaluate the cost of storage within the existing EOR project requires an extremely detailed analysis that incorporates CO₂ delivery costs over time, an actual schedule of injection volumes, detailed initial and expansion capital schedules, detailed conventional and EOR field operating costs, recycle equipment capital and operating costs, royalty and tax schedules, and an estimate of the most significant variable - commodity pricing. The IEA GHG Weyburn CO₂ Monitoring and Storage Project has created a model that will incorporate all the necessary variables to analyse CO₂ EOR projects. As an example, this model predicts that an additional 26 million tonnes of CO₂ (incremental to the current plan) could be stored in the reservoir if reasonable storage incentives existed to encourage operating the reservoir to maximize storage.

This model provides detailed economic and sensitivity analysis of potential EOR projects that need more than initial screening models. As projects proceed to the proposal stage, a more robust risk/sensitivity internal model may be required by the Operators to assist in the significant expenditure decisions usually involved with EOR projects

SUMMARY OF CO₂ COSTS

The costs at the time of the decision to start CO₂ injection, for Sleipner and Weyburn respectively are summarized in the table below.

The Sleipner equipment (compressor train and injection well) and operational procedures connected with the storage has, except for minor start-up problems, functioned as expected. Initially the injection well had problems with a rising injection pressure. After a standard gravel pack was put in place in the well, it has been stable. Over almost 8 years of injection, no lasting measurable rise in the injection pressure has been encountered. It was not to be expected either, since the cumulative injected volume is less than 8 Mt CO₂ and the overall storage capacity in the “Utsira” formation has been estimated to be 600 000 Mt CO₂ [3].

The Weyburn equipment and operational procedures were all well proven from previous EOR projects in the USA and elsewhere. The Weyburn oilfield has always been classified as a sour gas operation with very corrosive injection

waters. There were some initial start-up difficulties and an odour problem that resulted from mercaptans in the incoming CO₂ but they have been resolved and the EOR operation is stable.

TABLE 1: SUMMARY OF COSTS AT THE TIME OF THE DECISION TO START CO₂ INJECTION, FOR SLEIPNER AND WEYBURN

Historic Costs	SLEIPNER		WEYBURN	
	USD (1996)	%	USD (2000) per tonne	%
- Preparation	2 million	2		
- Compressors	79 - -“- -	82		
- Injection well	15 - -“- -	16		
Investments	96 - -“- -	100	10.19	51
Operations				
- per year	7 - -“- -			
- per tonne	7		9.85	49
TOTAL	- - -		20.04	100

(Exchange rate 1 USD = 8 NOK)

CONCLUSIONS

The numbers above should be treated with some care when trying to transfer them to another situation. Firstly offshore costs (Sleipner) are always some factor higher than on land. Secondly these costs are estimates of extra costs related to specific equipment in large field development projects. Thirdly, they are representative for the technology, methods and cost rates of the actual years; 1996 for Sleipner, 2000 for Weyburn.

As seen from the above table, the investment costs are not readily comparable. The circumstances were very different; one with a long pipeline to build and 19 patterns to connect, the other with a set of compressor trains and one injection well to install. The costs of operations are, however, comparable and in the range given by several studies.

ACKNOWLEDGEMENTS

The authors thank the operator; Statoil with licence partners; and the Petroleum Technology Research Centre for their permission to publish this paper. A number of colleagues are also thanked for giving support and advice.

REFERENCES

1. Baklid, A., R. Korbøl & G.A. Owren 1996. Sleipner Vest CO₂ Disposal, CO₂ Injection into a shallow Underground Aquifer. *SPE no 36 600*, SPE Annual Technical Conference, 1996, Denver, CO, USA
2. Torp, T.A., & J. Gale 2002. Storing CO₂ in Geological Reservoirs: The Sleipner and SACS Projects, *GHGT6 Paper*, GHGT6-Greenhouse Gas Technology Conference 6, 2002, Kyoto, Japan.
3. Holloway, S. (editor) 2003 *SACS Best Practice Manual*, Statoil Research Center, Trondheim, Norway.
4. IEA GHG Weyburn CO₂ Monitoring and Storage Project, <http://www.ieagreen.org.uk> "Practical Research"
5. Stevens, B.A. 1997 Case Study of the Enhanced Recovery Project in the Weyburn Field, Factors Impacting Oil and Gas Operations in Saskatchewan – *inSIGHT* Conference, November 6, 1997, Calgary, Alberta, Canada.
6. National Energy Board of Canada Hearing Order MH-1-98 available at publications@neb-one.gc.ca
7. Hattenbach, R.P., M. Wilson, K.R. Brown, 1998 Capture of Carbon Dioxide from Coal Combustion and Its Utilization for Enhanced Oil Recovery, GHGT-4 Conference, Interlaken, Switzerland.
8. J.E. Sinor Consultants Limited report on Dakota Gasification, Website <http://edj.net/sinor>
9. Hattenbach, R.P., K.R. Brown, 2000 Carbon Dioxide Re-Injection – CO₂ for Enhanced Oil Recovery, Weyburn Field, CAPP/CERI Industry Best Practices Conference (Question period) April 18-19, 2000 Calgary, Alberta, Canada.
10. Alberta Energy and Utilities Board Guide 60 (AEUB), December 2002, page 9