



ACID GAS INJECTION: A STUDY OF EXISTING OPERATIONS (PHASE I: INTERIM REPORT)

**Report Number PH4/15
January 2003**

*This document has been prepared for the Executive Committee of the Programme.
It is not a publication of the Operating Agent, International Energy Agency or its Secretariat.*

ACID GAS INJECTION: A STUDY OF EXISTING OPERATIONS (PHASE I: INTERIM REPORT)

Background to the Study

There are the 31 acid gas injection projects currently operating in Alberta, Canada. These provide an opportunity to learn about the injection and fate of CO₂ underground. The Alberta Research Council (ARC), the Alberta Geological Survey (AGS) and the Alberta Energy Utilities Board (AEUB), through Climate Change Central of Canada, proposed a 3-phase project to improve the geological and engineering knowledge about the injection and storage of CO₂ as a part of these acid gas injection schemes. The IEA Greenhouse Gas R&D Programme was offered the opportunity to participate in this work.

IEA GHG is currently participating in Phases I and II of the project:

- Phase I - a geological and engineering review of the 31 acid gas injection projects currently operating in Alberta, Canada.
- Phase II - a due diligence exercise on a selected site, which will help highlight any outstanding issues and develop an effective monitoring programme.

The two Phases would aim to quantify the volumes of CO₂ stored permanently in geological formations as a result of acid gas re-injection schemes. Phase III would be a monitoring project to assist in verifying the storage, safety and long-term fate of the injected acid gas.

Subsequently, because additional funding had become available from industrial sources, it was agreed by the Project Management Board (of which IEA GHG is a member) that Phase I will be expanded to include 7 additional operational acid gas injection sites in British Columbia, and 5 new sites (3 in Alberta and 2 in British Columbia), thus bringing the total number of acid gas injection sites to be studied in Canada to 43.

Each Phase of the proposed study will be reported separately. The Phase I report will summarize the geological characterization and technical operation of the 43 acid gas re-injection projects in Alberta and British Columbia. This interim report on Phase I provides details of the 31 original acid gas injection projects. The final report will provide details on all 43; this will be provided to IEA GHG in March 2003. The report will identify; what is common and what is specific to these acid gas injection operations. The findings will be useful for setting the criteria for selecting sites suitable for future acid gas re-injection and CO₂ storage and for developing the Phase III Monitoring project. The Phase II report will contain site specific confidential information; IEA GHG will receive only a summary of this Phase of the study, excluding any confidential data.

The study has been carried out by the Alberta Geological Survey and the Alberta Research Council.

Technical Background

A significant proportion of the raw natural gas production in the Alberta basin, Canada, contains varying percentages of acid gas components, specifically hydrogen sulphide (H₂S) and carbon dioxide (CO₂). The gas containing these components is normally referred to as “sour” gas. To meet pipeline and specifications for industrial and domestic sale, the sour gas must pass through gas processing facilities to separate out the acid gas components. Prior to 1988, if sulphur-recovery technology could not economically remove the sulphur from the acid gas, the alternative was to burn the acid gas in flare stacks or incinerators. Each flaring source was permitted to emit up to 10 t/day of sulphur. Since 1989, to reduce the waste and pollution resulting from sour-gas flaring, regulatory agencies in Alberta and British Columbia have required gas plants with a sulphur throughput of more than 1 t/day to recover the sulphur from the vent gas stream. The amount of sulphur to be recovered increases from 70% for plants producing between 1 and 5 t/day and to 96% for plants producing more than 10 t/day. Because of the

need to reduce emissions resulting from flaring, operators have turned to injection of the acid gas into geological reservoirs as an alternative.

The first acid gas injection operation in Alberta was started in 1989, and the next one in 1994. By the end of 1995, there were five acid gas injection schemes in operation, with another 12 in the process of application review. In 1998, there were 22 acid gas injection sites in Alberta. By the autumn of 2001, the number of acid gas operations had grown to 31 in Alberta and 7 in British Columbia. Since then, 5 more applications have been approved and have started operations (2 in Alberta and 3 in British Columbia); with another 2 in Alberta are awaiting approvals. The location of the 43 acid gas injection operations in western Canada is shown in Figure 1. In addition, one injection operation has recently been approved in Saskatchewan.

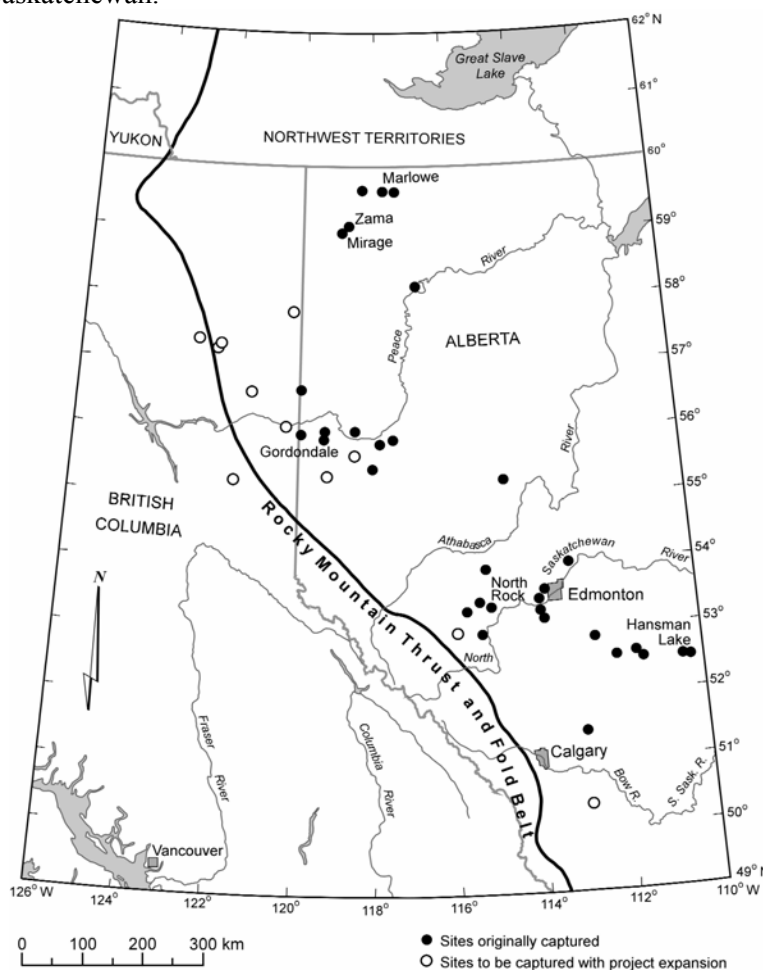


Figure 1: Location of Acid Gas Injection Sites in western Canada

Currently, acid gases are injected into a wide range of types of aquifers and oil/gas reservoirs in the Alberta basin, with a variety of acid-gas compositions and operating conditions. The composition of the injected acid gas varies from site to site, from 95% H_2S / 5% CO_2 to 5% H_2S / 95% CO_2 . Details of the various acid gas injection sites are given in the main report.

In 2000, the total approved rates for acid gas injection in Alberta reached over 1 300 000 m^3/day of CO_2 . Overall, approximately 1 Mt/y CO_2 was injected into geological reservoirs in the Alberta basin in 2001.

Results and Discussion

The following areas are discussed in the report:

- Regulation of acid gas injection sites in Canada.
- Operational knowledge base.
- Subsurface issues.
- Comparisons with other geological storage practices.
- Extrapolation of acid gas experience to CO₂ storage.

Regulation of acid gas injection sites in Canada

In both Alberta and British Columbia, there is a developed regulatory process for the approval of acid gas injection sites. The regulatory bodies concerned are: the Alberta Energy and Utilities Board (AEUB) and the British Columbia Ministry of Energy and Mines. In both cases, prospective operators are required to apply for and obtain approval before acid gas injection operations can commence. Before approving any operation, the regulatory agencies review the application to maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety. To adequately address these matters, the regulators require that the applicants submit detailed information regarding surface facilities, injection well configurations, characteristics of the injection reservoir or aquifer, and injection operations. After approval for acid gas injection is granted, the operators have to submit biannual progress reports to the regulatory agencies on their operations. Details of the information requirements for the approval process and progress reporting are given in the main report.

It is understood, from discussion with the contractor, that the approval stage is in essence be regarded as a negotiation process, as generally all applications are approved following detailed discussions between the regulator and the operator. When approval is granted a set of licensed operating parameters are established by the regulators, typically these include the following:

- Maximum well head and bottom-hole injection pressures
- Maximum daily injection rates and maximum injection volumes.

The setting of the injection pressures, in particular the bottom-hole injection pressure, is a key feature protecting the integrity of the reservoir. The bottom-hole injection pressure is set at 90% of the fracture pressure to ensure that fracturing of the cap rock does not occur. Typically, the fracture pressures are defined from pressure depth-correlation data for the Alberta basin if site specific tests have not been carried out. The regulatory bodies concerned will exercise powers to close down operations if they feel that safety procedures required by the approval schedule have been breached. To date, there have been two cases where operations have been shut down by the regulatory bodies because injection pressures were higher than scheduled in the approval. In one case an injection well blow out occurred.

Injection wells are typically considered as Class III wells under AEUB guidelines¹ which covers wells injecting hydrocarbon, inert and sour gases². It is noted that the same well classification for acid gas injection applies to CO₂ injected for enhanced oil recovery in Canada. Testing and cementing requirements for Class Ib, II and III wells are somewhat less stringent than for Class 1a wells that are designated for the injection of oil field and industrial waste fluids³. However, Class Ib, II and III wells have to be designed to ensure that useable water bearing zones are isolated.

¹ Alberta Energy Utilities Board, Guide 51, Injection and Disposal Wells – well classifications, completion, logging and testing, March 1994.

² It is noted in several operations the acid gas is dissolved in the produced water and hence when injected the well classification becomes IB or II

³ Fluids to be injected in Class 1a wells include: phenolic waste waters, acid or caustic solutions, aqueous solutions of halogenated organic compounds, solutions containing heavy metals.

The regulatory bodies also require that an Emergency Planning zone is established around the injection well in the case of an accidental release of acid gas. The operators are required to have a detailed emergency response plan (ERP) for use in the event of a leak. To have an effective ERP, the area surrounding the injection site should be equipped with H₂S detection and alarm systems, windsocks, self-contained breathing apparatus, and remote unit and plant shutdown stations.

Operational knowledge base

Considerable experience in the operation of these acid gas injection facilities has now been built up. The knowledge base relates principally to surface and injection well operations. One of the key design features is the injection well, which has to be designed and operated to prevent accidental release of the acid gas. The injection well typically consists of a central steel tubing “string” (i.e. series of connected tubes) with an outer annulus bounded by a steel casing, which is cemented to the subsurface formations. Several safety features are incorporated in the injection well to prevent leakage. The casing is isolated from the tubing string and the acid gas by installing a “packer” in the annulus between the casing and the tubing string just above the subsurface storage formation. This is pressure tested for integrity once a year. A down-hole safety valve or check valve can be incorporated in the tubing string so that if something fails at the surface, the flow of acid gas from the formation will be prevented. The well head of the injection well is similarly protected with valves.

Usually the pipelines carrying acid gases are short (up to 1500m, but generally 100 to 200m)⁴ and typically are constructed of mild steel. Only the short distance pipelines are constructed from stainless steel, typically they are constructed of carbon steel.. Corrosion is avoided by dehydrating⁵ the acid gas, which also prevents hydrate formation and thus assists in preventing compressor breakdown and plugging.

Subsurface issues

The location of the injection well is another key design feature of any acid gas injection project. Its location is based on a detailed assessment of the regional geology and hydrogeology, designed to evaluate the potential for leakage. Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short-and long-term fate of the injected acid gas. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface. However, it is noted that although migration pathways are an issue in the choice of location of the injection well, no subsequent subsurface monitoring is required by the regulatory bodies to study whether migration is occurring. Considering the toxic nature of the acid gas and the fact that much of Canada’s water supplies come from underground reservoirs this issue is worth considering further.

Reaction of the acid gas within the reservoirs is a potentially significant issue. Work by the Alberta Research Council has indicated that, depending on the mineralogy of the reservoir, both the CO₂ and H₂S will dissolve in the formation water within reservoir. If dissolution does occur, then there is the potential that some mineral fixation might occur. Generally for CO₂, the degree of mineral fixation that occurs is limited (only a few percent of total injection volume within hundreds of years) in both carbonate and sandstone reservoirs. The extent to which the injected H₂S might be trapped by mineral fixation is an important question to be resolved.

Reaction of the acid gas with the cap rock (which in most cases are shales) and with the cements in the injection wells (both in existing and old abandoned wells that are punctuating the reservoir) are both important issues that could lead to migration of the injected gas out of the reservoir. The degree of reaction of the acid gas with the cap rock and injection well cements needs to be fully understood.

⁴ There are several cases with pipeline distances of 2500 to 5500 m

⁵ Moisture contents of less than 0.5 mole % are maintained by removing the water condensed after each compression stage rather than using a separate dehydration stage.

Comparisons with other geological storage practices

There are some interesting comparisons that can be drawn with other gas storage operations that can warrant discussion principally relating to monitoring requirements.

Despite the fact that acid gas is both strongly acidic (and because of its H_2S content toxic) the regulations in place in Canada for acid gas injection do not include monitoring of overlying aquifers, particularly where the injection is made into deep saline aquifers. This contrasts with natural gas regulations in Europe which call for the monitoring of vertical leakage by gas migration (if any) towards the aquifers located above the reservoir to ensure that leakage remains minimal and acceptable. Also, any lateral gas spread is to be monitored using a set of wells⁶. The European gas storage regulations require much less extensive monitoring for oil and gas fields, the inference that can be drawn is that it is considered that these reservoirs are less likely to leak than aquifers.

In a study undertaken by Battelle for the USDOE⁷ it was suggested that an injection well for CO_2 into an aquifer would be Class I under the provisions of the Underground Injection Control (UIC) programme of the Federal Safe Drinking Water Act. Class I wells are wells that inject hazardous or non-hazardous wastes into geological formations and require a permit. Much of the information required in the permit applications for Class I wells in the USA appear to be similar to those for acid gas injection in Canada. One area where the regulations differ is that in the USA detailed groundwater modelling studies are required to study plume migration and monitoring will be required of surface water and overlying aquifer used for water abstraction.

There are a number of operational acid gas injection operations in the USA, comparison of their regulatory requirements and monitoring requirements with those in Canada might provide additional information and insight into practises that might be adopted for CO_2 storage.

Extrapolation of acid gas injection experience to CO_2 storage

Acid gas injection operations can be regarded as more hazardous operations than for CO_2 injection alone. The primary reason for this is the presence of H_2S which is a highly toxic chemical species. Regulations framed for acid gas injection, therefore, should be more stringent than those for CO_2 injection alone and could be deemed as not directly relevant. However, the regulations will provide a useful bench mark for CO_2 storage⁸, particularly if one assumes that to gain public acceptance for widespread CO_2 storage in geological reservoirs, some over-design and regulation might be necessary in the early years of implementation of the technology.

Any operation where gases are injected into geological reservoirs will provide information that will help develop confidence in geological storage of CO_2 . In the case of acid gas injection if it can be demonstrated that the injected acid gases have been contained within the geological reservoirs, that cement integrity in the injection wells has not been compromised and there are no associated environmental problems, then this should build confidence that CO_2 alone will be stored effectively as well. However, at present it might be difficult to demonstrate credible evidence for acid gas containment within a geological reservoir without a detailed monitoring programme being undertaken at an acid gas injection site.

⁶ IEA Greenhouse Gas R&D Programme File Note on Geological Storage of CO_2 - Conflicts with and experience to be gained from natural gas storage, 4th January 2001.

⁷ Project No. DE-RAC26-98FT40418, Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment – Final Technical Report, July 9, 2001

⁸ Regulations on acid gas operations in Canada have been included in the study currently underway that will develop a discussion document on Guidelines for CO_2 Storage in Geological Media. A draft report on this study is expected in early 2003.

Expert Group Comments

The draft of this report was sent to a panel of expert reviewers and to a number of the IEA GHG Programme's members who had expressed interest in reviewing it. Generally the comments received focused on editorial issues. However, a number asked for additional information to be supplied including: adding the Alberta and British Columbia guidelines as appendices, including details on whether any applications been rejected (if so why), listing completed or abandoned projects, and any lessons to be learnt, as well as information on monitoring and if there were any reportable incidents. These comments have now been discussed with the contractor and will be dealt with in the final report for Phase I of the project.

Major Conclusions

Currently over 1 Mt/y of acid gases (H_2S) and CO_2 are being injected into deep saline aquifers and depleted oil and gas fields in Alberta, Canada. Whilst the quantities of gas injected are modest compared to the amount of CO_2 injected in CO_2 -EOR operations in the USA and Canada, nevertheless there is a considerable body of knowledge that can be drawn upon for reference in connection with wide scale implementation of CO_2 storage in the future. Information and experience exists on the regulation of acid gas injection sites and the design and operation of compressors, pipelines and injection wells that are relevant to larger CO_2 storage operations.

The regulatory procedures in place for acid gas injections focus principally on the surface and injection well activities, with close attention paid to preventing leakage from the injection well above and underground and the prevention of loss of containment through reservoir fracturing. Monitoring of the acid gas injection projects is currently limited to surface installations and injection well operations. The experience that could be gained from these projects could be broadened considerably if sub-surface monitoring was included at a specific site or at several sites reflecting the range of reservoirs that are being used for acid gas storage purposes. Such monitoring activities could provide detailed knowledge of the impacts of impurities, as well as the behaviour of CO_2 in geological reservoirs which would help build our understanding of the impacts of injection of CO_2 and other gases in geological reservoirs.

Recommendations

In addition, to the acid gas injection operations in Canada there are a further 10 sites in the USA, mostly in Wyoming. It would be useful to collate details of the regulatory procedures in the USA for these sites to see if they are comparable or contrast in any way. Also if similar details as those in the Canadian data set could be compiled on the acid gas operations in the USA, then this would provide a single comprehensive overview of acid gas operations in North America. Such an overview could be done as an extension to this project or as a separate study.

Consideration should be given to developing a monitoring project at a new acid gas injection facility (or at several facilities reflecting the range of reservoirs that are being utilized) to assist in the development of the knowledge of injection of CO_2 and other gaseous species. Such a project should consider both surface and sub-surface monitoring to provide confidence on containment of the injected gas in the reservoir and to discount any surface migration.

Characteristics of Acid Gas Injection Operations in Western Canada

Interim Report to

International Energy Agency – Greenhouse Gas R&D Programme

Dr. Stefan Bachu
Alberta Geological Survey
Alberta Energy and Utilities Board

Dr. William D. Gunter
Alberta Research Council

August 2002

Contents

Introduction	3
Acid gas injection operations	4
Compilation project.....	4
Historical background	6
Site selection and operations.....	9
Acid gas properties	9
Surface operations	10
Subsurface considerations	12
Review of operations in Alberta	13
Subsurface characteristics	14
Licensed operations.....	15
Surface characteristics.....	15
Issues	16
Conclusions	17
References	19
Appendix	21

Figures

Figure 1: Location of the Alberta basin in Canada.....	3
Figure 2: Location of acid gas injection sites in the Alberta basin	5
Figure 3: Cumulative volumes of CO ₂ and H ₂ S licensed for injection as acid gas in Alberta up to Fall 2001	9
Figure 4: Phase diagrams for methane (CH ₄), carbon dioxide (CO ₂), hydrogen sulphide (H ₂ S) and a 50%-50% acid gas mixture; hydrate conditions for CO ₂ and H ₂ S; and a 4- stage acid-gas compression cycle	10

INTRODUCTION

Over the past decade, oil and gas producers in the Alberta basin in western Canada (Alberta and British Columbia) (Figure 1) have been faced with a growing challenge to reduce atmospheric emissions of hydrogen sulphide (H_2S), which is produced from “sour” hydrocarbon pools. Since surface desulfurization through the Claus process is uneconomic and the surface storage of the produced sulfur constitutes a liability, more and more operators are turning to acid gas disposal by injection into deep geological formations. Acid gas is a mixture of hydrogen sulphide and carbon dioxide (H_2S and CO_2) that is the byproduct of “sweetening” sour hydrocarbons. In addition to providing a cost-effective alternative to sulfur recovery, the deep injection of acid gas reduces emissions of noxious substances into the atmosphere and alleviates the public concern resulting from sour gas production and flaring.

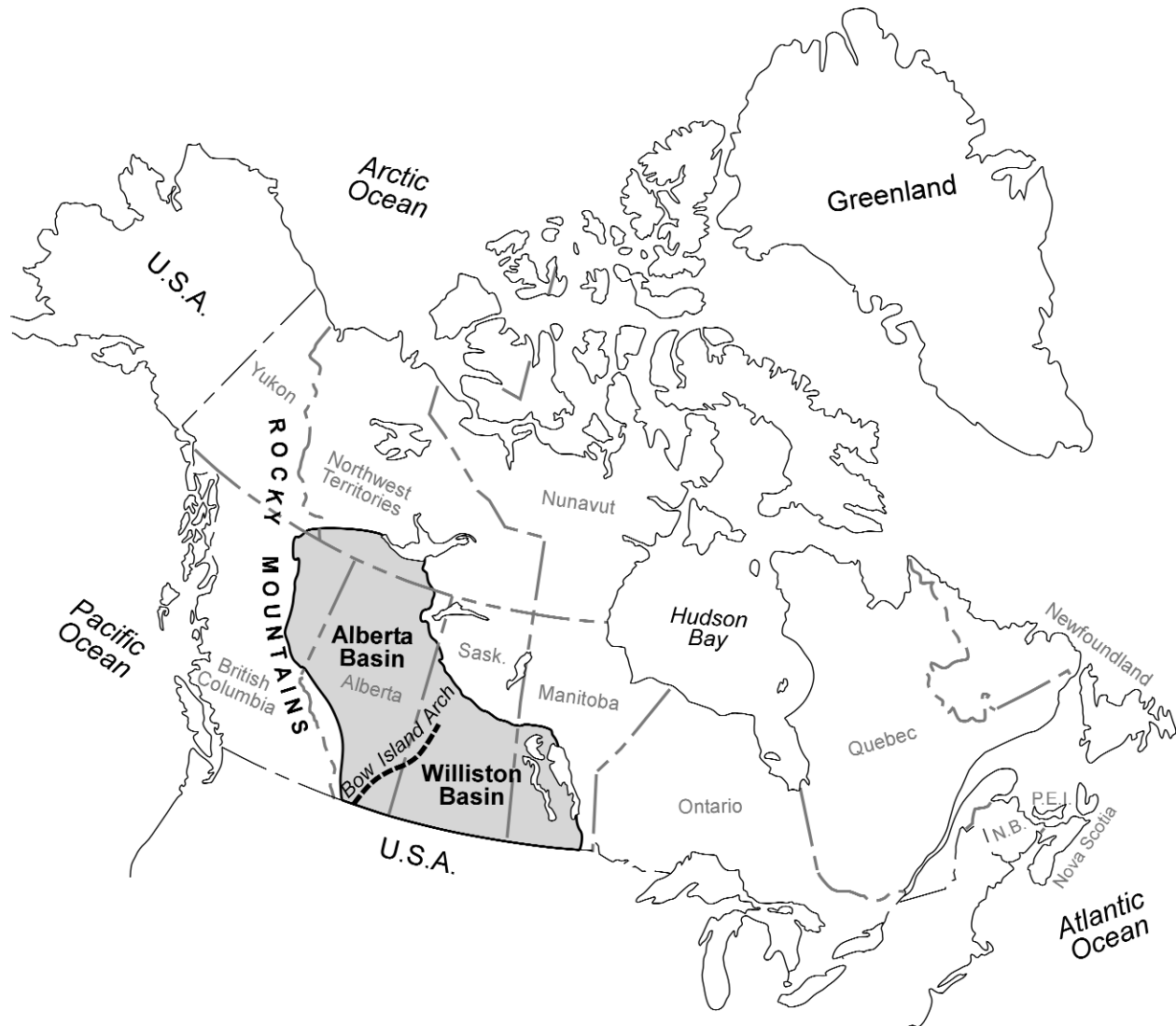


Figure 1: Location of the Alberta basin in Canada.

Although the purpose of the acid gas injection operations is to dispose of H_2S , significant quantities of CO_2 are being injected at the same time because it is uneconomic to separate the two gases. In the context of current debates and research regarding global climate change as a result of anthropogenic greenhouse gas emissions, of which CO_2 is the most important, the acid gas injection operations in western Canada represent an analogue to geological sequestration of CO_2 . This option is an immediately-available and technologically-feasible means of reducing CO_2 emissions into the atmosphere that is particularly suited for land-locked regions located on sedimentary basins, such as the North American mid-continent. Large-scale injection of CO_2 into depleted oil and gas reservoirs and into deep saline aquifers is one of the most promising methods of geological sequestration of CO_2 , and in this respect it is no different from acid gas injection operations. However, before implementation of greenhouse gas geological sequestration, a series of questions need addressing, the most important ones relating to the short- and long-term fate of the injected CO_2 . Thus, the study of the acid gas injection operations in western Canada provides the opportunity to learn about the safety of these operations and about the fate of the injected gases, and represents a unique opportunity to investigate the feasibility of CO_2 geological sequestration.

Acid Gas Injection Operations

In Alberta, the Oil and Gas Conservation Act requires that operators apply for and obtain approval from the Alberta Energy and Utilities Board (EUB), a provincial regulatory agency, to dispose of acid gas. Similarly, in British Columbia (B.C.) operators have to apply to B.C. Ministry of Energy and Mines for approval. Before approving any operation, the regulatory agencies review the application to maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety. To adequately address these matters, the regulators require that the applicants submit information regarding surface facilities, injection well configurations, characteristics of the injection reservoir or aquifer, and operations. After approval for acid gas injection is granted, the operators have to submit to the regulatory agencies biannual progress reports on the operations.

The first acid gas injection operation in Alberta was started in 1989, and the next one in 1994. By the end of 1995, there were five acid gas injection schemes in operation, with another 12 in the process of application review. In 1998 there were 22 acid gas injection sites in Alberta. In the Fall of 2001, the number of acid gas operations in western Canada grew to 31 in Alberta and 7 in British Columbia. Since then, 5 more applications have been approved and have started operations (2 in Alberta and 3 in B.C.), with another 2 in Alberta pending approval. The location of the 45 acid gas injection operations in western Canada is shown in Figure 2.

Compilation Project

In January 2002, the Alberta Geological Survey (AGS), a group in the Alberta Energy and Utilities Board, and the Alberta Research Council (ARC), jointly undertook a project funded by Canadian federal and provincial governments and agencies, and by the IEA Greenhouse R&D Programme, to review the information submitted to EUB by operators in the process of obtaining approval for and running the 31 acid gas injection operations active in Alberta, in or prior to December 2001 (Figure 2). AGS is reviewing the subsurface characteristics and the ARC is

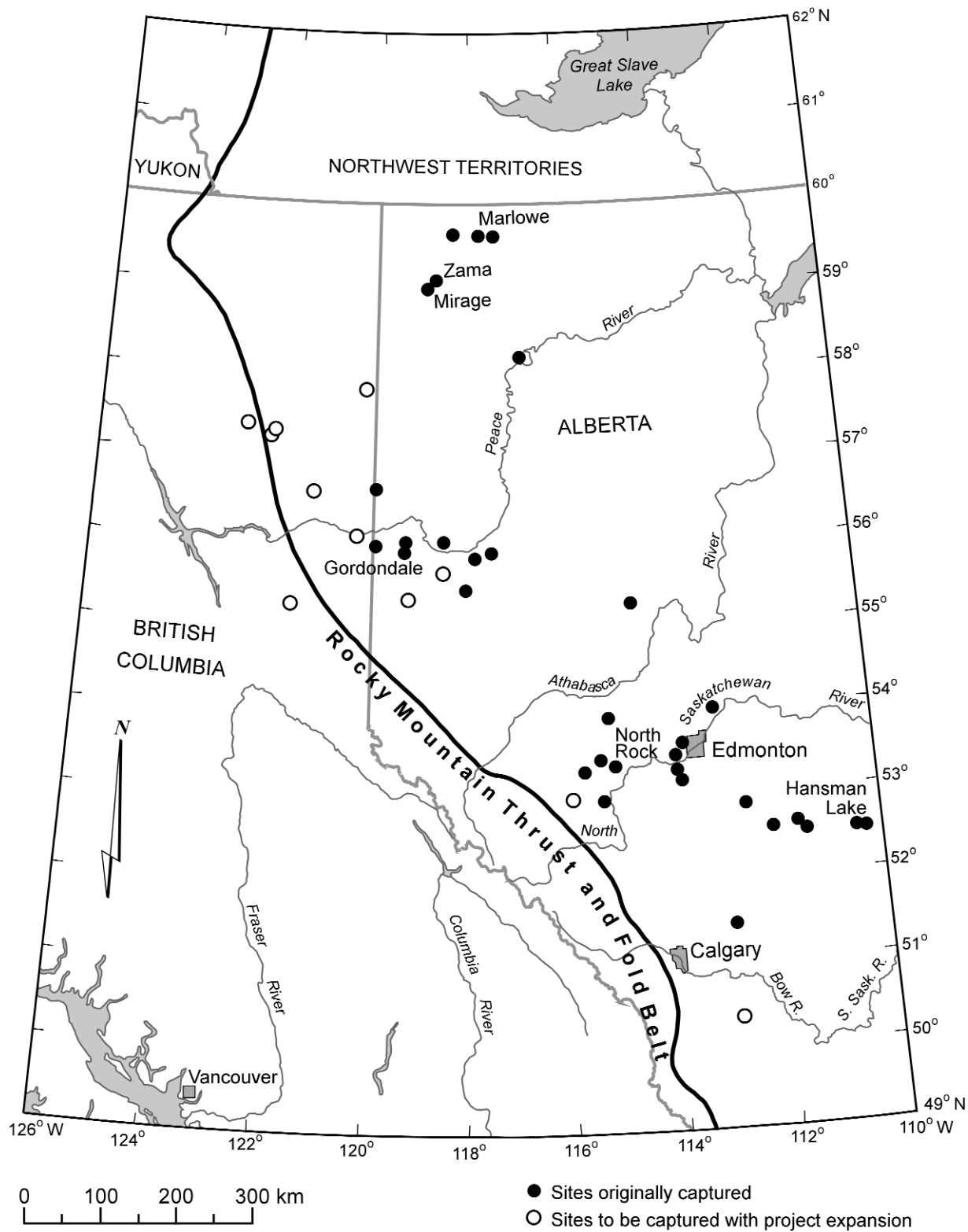


Figure 2: Location of acid-gas injection sites in the Alberta basin.

reviewing the surface facilities of these operations. The original deadline of the project was September 2002. In June 2002, the first industry participant joined the project, at which time the funding agencies agreed to expand the scope of the project to include the 10 acid gas injection operations in British Columbia and the additional 4 acid gas operations in Alberta (2 already approved and 2 pending approval). Concomitantly, the project deadline was extended to March 31, 2003. This interim report presents results to date of the review of the original 31 sites in Alberta, as per the terms of the original contract.

Historical files with the respective regulatory agencies in Alberta and British Columbia were searched for applications for acid gas injection operations, for approvals and for the subsequent progress reports submitted by operators. Relevant information from these hard copy documents was entered into a specially-designed database. Several synthesis reports (tables) were generated that compile and present information from the acid gas injection sites. These reports and associated graphs are included in the Appendix.

With regard to the reviewed documentation, this interim report contains all the information currently existing with the Alberta Energy and Utilities Board for the initial 31 sites in Alberta. Documentation is missing or was not captured in the following cases:

- The original application for Marlowe is missing, for unknown reasons.
- Applications for the Redwater and Belshill Lake sites do not exist because they did not require an acid-gas application since they were originally water disposal sites that changed to “sour-water”.

It must be emphasized here that the information presented herein is “**as submitted**” by the operators, with no additional checking and interpretation by AGS and/or EUB staff, except for evidently and blatantly wrong data. The data were adequately checked for data-entry accuracy, but were not checked for validity. Any data inconsistencies reflect the data and information as submitted to EUB by operators. Missing data for some sites are due to the lack of submissions by operators, or to unavailability within EUB. In cases that data and information were not submitted, no additional search was performed to fill in from other sources. The verification of the submitted information and collection of additional data should be the purpose of another, continuing project.

HISTORICAL BACKGROUND

A significant portion of raw natural gas production in the Alberta basin, Canada, contains varying percentages of acid gas components, specifically hydrogen sulphide (H_2S) and carbon dioxide (CO_2). To meet pipeline and sales gas specifications, this raw sour natural gas must pass through gas processing facilities to separate out the acid gas components. Furthermore, a number of sour oil pools produce solution gas that contains significant amounts of H_2S and CO_2 (e.g., 4% and 17% respectively at the Wayne –Rossdale; Ho *et al.* 1996). Prior to 1988, if sulfur-recovery technology could not economically remove the sulfur from the acid gas, the alternative was to burn the acid gas in flare stacks or incinerators. Each flaring source was permitted to emit up to 10 t/d of sulfur. To reduce the waste and pollution resulting from sour-gas flaring, regulatory agencies in Alberta and British Columbia require since 1989 that gas plants with a sulfur throughput of more than 1 t/d recover the sulfur from the gas stream (Longworth *et al.* 1996). The amount of recovered sulfur increases from 70% for plants producing 1 to 5 t/d, to 96% for plants

producing more than 10 t/d. Nevertheless, even with sulfur recovery in place, significant volumes of tail, or acid gas, are generated, and this is often flared from stacks at the well sites. In the early '90s, the yearly average emission from gas flaring in the Alberta basin was in the order of 0.3 Mt SO₂ and 6 Mt CO₂ (Longworth *et al.* 1996).

Until the late '80s and early '90s, sulfur recovery and acid gas flaring were considered the most economic ways of dealing with the sulfur in sour and acid gases. As a result of public concern about flaring, including environment degradation, human and animal health, and waste, the regulatory agencies require more and more that operators reduce emissions, particularly in areas of high public concern. Because the sulfur world supply is dominated by recovered sulfur and environmental pressure has driven desulfurization to the point that the supply has exceeded demand, large tonnages of sulfur are being poured into block storage throughout the world, including the Alberta basin (Connock 2001). Since desulfurization is uneconomic in a weak sulfur market, and flaring is publicly unacceptable, more and more operators in the Alberta basin are turning to acid gas disposal through injection into deep subsurface formations, mostly in saline aquifers, but also in depleted oil and gas reservoirs. The on-site geological disposal is particularly attractive if, otherwise, operators have to build their own sulfur recovery plant or a pipeline to the nearest plant with available capacity, each alternative having its own undesirable effects (Keushnig 1995).

These acid gas injection sites in the Alberta basin are by and large located mostly in the region close to the Rocky Mountain Thrust and Fold Belt that corresponds to sour gas production from deep reservoirs (Figure 2). Two sites in B.C. are actually located within the thrust and fold belt. At 26 sites the acid gas is injected into deep saline aquifers in regional-scale flow systems confined by regional-scale aquitards, with the remainder of sites injecting into depleted oil and gas reservoirs. The acid gas could increase oil or gas recovery if it is injected to maintain reservoir pressure (Longworth *et al.* 1996; Connock 2001). Because site selection and approval must meet a set of stringent criteria imposed by regulatory agencies to address H₂S emissions (Keushnig 1995; Longworth *et al.* 1996), the sites meet also the criteria for and are located in areas suitable for CO₂ sequestration in geological media in the Alberta basin (Bachu 2000; Bachu & Stewart 2002).

In 1989, Chevron Canada Ltd. started the first acid-gas injection operation at Acheson, on the outskirts of Edmonton in Alberta, designed to handle a mixture of 15% H₂S and 85% CO₂ by injecting it at a depth of 1100 m into a depleted sandstone oil reservoir (Lock, 1997). The operation experienced elemental sulfur deposition, which plugged the injection well (Longworth *et al.*, 1996). The next operation, by a different company, started in 1994 by injecting 20% H₂S and 80% CO₂ into a water-saturated carbonate reef in central Alberta. Also in 1994, Chevron Canada Ltd. started acid gas injection at 30MPa pressure into a carbonate aquifer 2800 m deep at Pembina, west of Edmonton. The acid gas composition is 74% H₂S, 21% CO₂, 1% hydrocarbon gases, and water for the remainder (Lock, 1997).

In 1995, PanCanadian Petroleum Ltd. started mixing, at surface, acid gas with produced water at elevated pressure, and injected the solution ("sour water") into a water-saturated sandstone zone underlying an oil pool at Hansman Lake, and into a deep, dolomitized carbonate-shelf aquifer at Thompson Lake in eastern Alberta (Kopperson *et al.* 1998a,b). Both injection zones are overlain

by shales. The sandstone aquifer has high porosity (30% on average) and permeability (up to several darcies, or 10^{-12} m²), while the carbonate zone has 22% porosity. Also in 1995, PanCanadian started an acid-gas injection operation at Wayne-Rosedale, northeast of Calgary in Alberta. The acid gas mixture (20% H₂S and 80% CO₂), with an estimated daily production rate of 21,000 m³/d, was the result of sweetening a 34°API oil with an associated solution gas containing 4% H₂S and 17% CO₂ (Ho *et al.*, 1996). Injection takes place in a 26 m water-saturated carbonate-reef unit, characterized by 6% porosity, 150×10^{-15} m² (150 md) permeability, 65°C temperature and 15.5 MPa formation pressure, confined by tight dolomite units. At in situ conditions, the acid gas density is ~543 kg/m³ (Ho *et al.*, 1996).

In 1995, Penzoil Canada Inc. started injecting a mix of 20% H₂S and 80% CO₂ at 120,000 m³/d into a depleted oil reservoir in a pinnacle carbonate reef ~1510 m deep at Zama X2X in northern Alberta. Because acid gas is miscible with oil, at one point during the operation it was used in conjunction with a miscible-flood scheme to enhance the oil recovery (Davison *et al.*, 1999). The ~115 m dolomitized reef with an average porosity of 7.6% is underlain by ~45 m of tight lime mudstone and is overlain by 60 to 90 m of anhydrite. The critical point of the acid gas mixture is 42°C and 7.64 MPa. At target operating conditions of 14.5 MPa and 76°C (initial reservoir pressure and temperature), the injected acid gas is supercritical, with a density of ~500 kg/m³ and a viscosity of 0.04 cp (Davison *et al.*, 1999). The caprock threshold displacement pressure was measured in the laboratory to be 22.3 MPa. Considering that the initial differential pressure across the caprock is ~7 MPa, the maximum operating pressure was established at 30 MPa. Because the formation water naturally contains significant amounts of both CO₂ and H₂S, acid gas injection was not expected to cause dissolution of reservoir rock and/or precipitation.

The West Stoddart acid gas injection operation in British Columbia, which started in 1998, is the largest to date in the Alberta basin and the world, with a licensed capacity of 390,000 m³/d, but operating only at 280,000 m³/d. The acid gas stream contains 85% H₂S and 15% CO₂ (340 and 78 t/d H₂S and CO₂, respectively).

The acid gas is or was mixed with water at surface, prior to injection, at the following sites: Mitsue Wabamun, Provost-Leduc (up to 1999), Hansman Lake, Mirage, Redwater and Belshill Lake. The last two are actually water disposal sites with a minor amount of dissolved acid gas (“sour water” disposal) and injection at these sites is done “randomly” through 49 and 19 wells, respectively. Because these are water disposal schemes approved previously as such, the operators did not have to submit a special application to the regulatory agency to inject sour water. The Hansman Lake, Gordondale Halfway, and Mirage sites (Figure 2) were rescinded in 1997, 1998 and 1999, respectively. The Zama X2X and Z3Z sites stopped injecting (shut in) in May 1998 and December 2000, respectively. One operation, at Northrock, although approved, was never implemented.

Currently, acid gas injection in the Alberta basin occurs over a wide range of aquifer and reservoir characteristics, acid-gas composition, and operating conditions. The composition of the injected acid gas varies from site to site, from 95% H₂S and 5% CO₂ to 5% H₂S and 95% CO₂. In 2000, the total approved rates for acid gas injection in Alberta reached more than 1,300,000 m³/d CO₂ and 900,000 m³/d H₂S (Figure 3). Considering also the seven acid gas injection sites in British

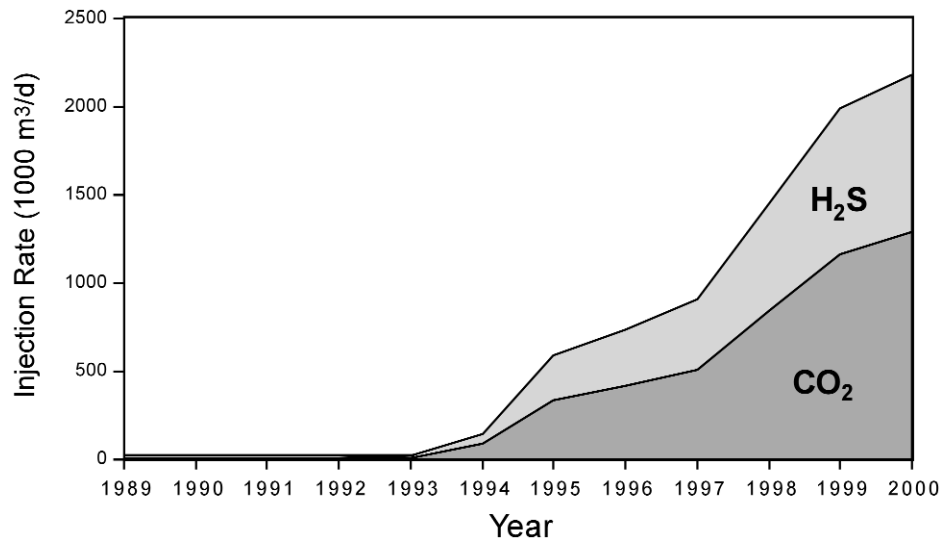


Figure 3: Cumulative volumes of carbon dioxide and hydrogen sulphide licensed for injection as acid-gas in Alberta.

Columbia, approximately 1 Mt CO₂ was injected in geological media in the Alberta basin in 2001, driven by the need to dispose of H₂S.

SITE SELECTION AND OPERATIONS

The selection of an acid-gas injection site needs to address various considerations which relate to: proximity to sour oil and gas production that is the source of acid gas; confinement of the injected gas; effect of acid gas on the rock matrix; protection of energy, mineral and groundwater resources; equity interests; wellbore integrity and public safety (Keushnig 1995; Longworth *et al.* 1996). The surface operations and the subsurface aspects of acid gas injection depend on the properties of the H₂S and CO₂ mixture, which include, but are not limited to non-aqueous phase behavior, water content, hydrate formation and the density and viscosity of the acid gas (Carroll & Lui, 1997; Ng *et al.* 1999). Knowledge of the phase equilibria for acid gas allows the optimization of the injection process while addressing corrosion, hydrate formation and compressor-outlet pressure concerns.

Acid Gas Properties

The acid gas obtained after the removal of H₂S and CO₂ from the sour gas may also contain 1% to 3% hydrocarbon gases, and is saturated with water vapor in the range of 2 to 6%. In general, the ability of acid gas to hold water increases with temperature and decreases with the addition of small amounts of methane. However, as pressure is applied on an acid gas mixture, the capacity of the acid gas to hold water decreases to a minimum and then the water solubility increases at higher pressures. This mixture is usually compressed from about 100 kPa to around 8 to 10 MPa for injection (Wichert & Royan 1996) and the water content is generally reduced to less than half a mole %.

While there aren't many published properties of the acid gas mixture, the properties of pure CO_2 and H_2S have been thoroughly examined and reported. In their pure state, CO_2 and H_2S exhibit the normal vapour/liquid behavior with pressure and temperature (Figure 4), with CO_2 condensing at lower temperatures than H_2S . Methane (CH_4) also exhibits this behavior, but at much lower temperatures. The phase behavior of the acid gas binary system is represented by a continuous series of two-phase envelopes (separating the liquid and gas phases) located between the unary bounding systems in the pressure temperature space (Figure 4). If water is present, both CO_2 and H_2S form hydrates at relatively low temperatures, up to 10°C for CO_2 and more than 30°C for H_2S (Carroll and Lui, 1997).

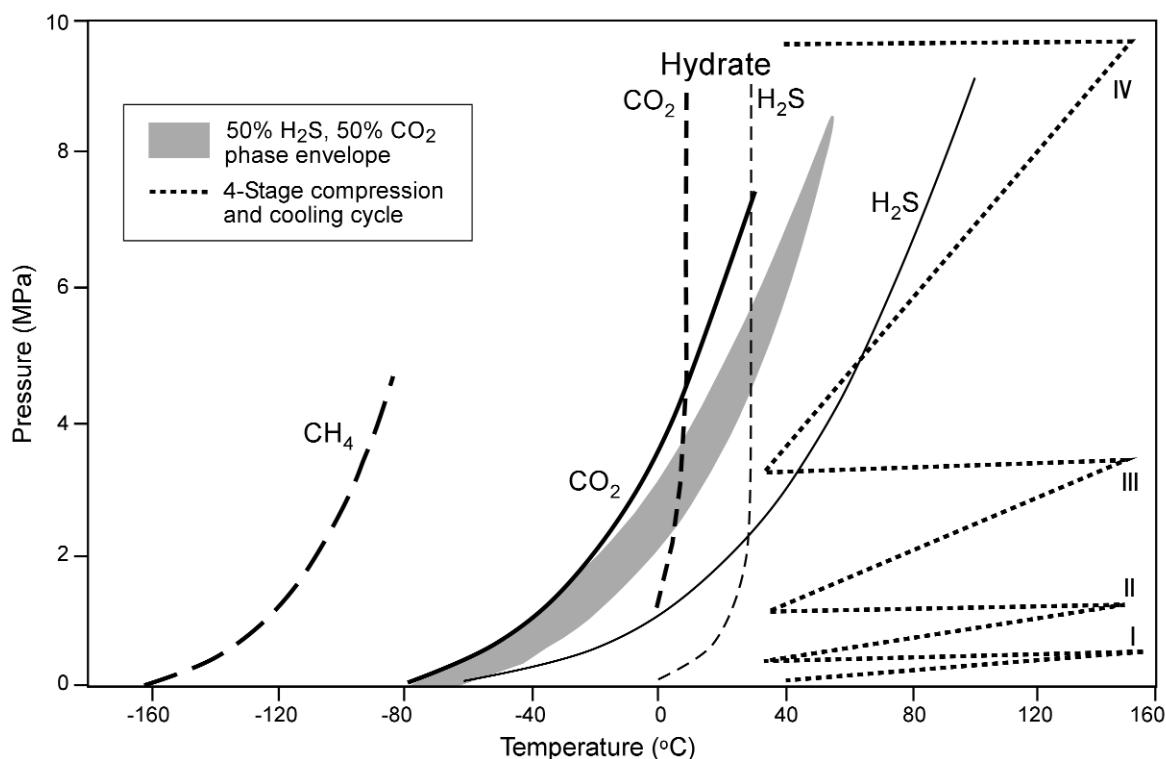


Figure 4: Phase diagrams for methane (CH_4), carbon dioxide (CO_2), hydrogen sulphide (H_2S) and a 50%-50% acid-gas mixture, hydrate conditions for CO_2 and H_2S , and a 4-stage acid-gas compression cycle (after Wichert and Royan, 1996).

Surface Operations

The sweetening of acid gas takes place at gas processing plants where the natural gas is processed to reach pipeline and sales specifications. After separation of any gas liquids, the sour gas is flowed through a contactor or absorber tower in a one or two stage process where the sour gas typically comes in contact with an amine solution. The amine reacts with the acid gas, trapping it in the water phase and allowing the sweet components of the natural gas to pass on through. By the time the natural gas reaches the top of the tower, all of the CO_2 and H_2S should have been absorbed by the amine solution. Because the cost of the separation step is a major part of the acid gas injection operation, better amine forms are being developed to increase the efficiency of the process, and, in some cases, other solvents are being considered (e.g. K_2CO_3).

After separation, the gas is now sweet, meeting pipeline and market specifications for allowable acid gas content. The gas-saturated amine solvent is collected from the bottom of the tower and is regenerated by heating the aqueous solution to approximately 170°C. The water-saturated acid-gas stream leaves the regeneration unit at 35 to 70 kPa and must be cooled and then compressed in excess of the subsurface storage formation pressure for injection. Typically, four stages of compression are required to provide the required discharge pressure (Figure 4). During compression, the acid gas mixture heats up and, therefore, cooling is required after each stage of compression. It is desirable to keep the compression cycle at a higher temperature than the stability field for hydrates to prevent compressor breakdown and plugging. The hydrate-forming temperature at any pressure of an acid gas increases with increasing content of H₂S. In the limit, compression temperatures maintained above 35°C will avoid hydrates forming (Figure 4).

Even if hydrate forming is avoided, excess water accelerates corrosion of the steel in contact with the acid gas, and is the main reason why dehydration of the acid gas is needed. Compression will tend to dewater the acid gas up to a maximum pressure between 3 and 5 MPa if there are no hydrocarbon impurities present. This pressure maximum reflects the pressure at which the acid gas mixture is in the dense liquid phase form, where the solubility of water can increase substantially with increasing pressure due to the molecular attraction between these polar compounds (Wichert and Royan, 1996). Compressing the acid gas to higher pressures increases the solubility of water in the acid gas and more than counteracts the decrease in solubility due to interstage cooling. Hence, a separate dehydration step may not be needed (Clark et al., 1998). Thus, by collecting the condensed water during each compression stage and by keeping the temperature a few degrees above the hydrate stability temperature, the probability of hydrate formation and corrosion are minimized, and lower-quality, less expensive steels can be used for transporting the acid gas mixture to the subsurface storage formation.

To avoid pump cavitation, the acid gas must not enter the two-phase region during compression. Higher temperatures, although required in the process to avoid hydrate formation and plugging of the lines, lead to accelerated corrosion. Both plugging and corrosion can lead to containment failure. Additional safety precautions require addition of chemical inhibitors to the acid gas stream (for example methanol to lower hydrate formation temperatures, and glycol to extract the excess water from the acid gas stream) or use of specialty corrosion-resistant steels. Both add to the cost of the operation. Corrosion monitoring is normally done to assess the effectiveness of the treatments.

Once the acid gas is compressed, it is transported through a pipeline to the injection wellhead usually at a short distance from the gas plant. The well consists of a central steel tubing string with an outer annulus bounded by a steel casing, which is cemented to the subsurface formations. The acid gas flows down the well tubing to the subsurface storage formation depth and across the well casing, through perforations in the casing, to the subsurface storage formation. The discharge pressure from the compressor must exceed the sum of the formation pressure, the pressure loss due to friction in the line from the compressor to the wellhead, friction loss in the tubing string, pressure drop across the perforations, pressure loss/gain due to elevation change from the compressor to the well head, and pressure-head gain due to the liquid column in the tubing string. Ultimately, the discharge pressure must consider the desired injectivity into the subsurface storage formation, which depends on the thickness and permeability of the formation and on the viscosity

and density of the acid gas at in situ conditions. The high pressures after the fourth compression stage stabilize, upon cooling, the high-density liquid-phase of the acid gas, which can have a density of approximately 75% of the density of water, providing the hydrocarbon content is not greater than approximately 2%. Considering that in most cases the pressure of the subsurface injection formation is near hydrostatic, the hydraulic head provided by the acid gas provides a significant amount of the total pressure required to inject it into the subsurface formation.

Several safety features are incorporated in the injection well to prevent leakage. The casing is isolated from the tubing string and the acid gas by installing a packer in the annulus between the casing and the tubing string just above the subsurface storage formation, which is pressure tested for integrity once a year. A down-hole safety valve or a check valve can be incorporated in the tubing string so that if something fails at surface, the flow of acid gas from the formation will be prevented. The wellhead of the injection well is similarly protected with valves.

Although a number of safety valves are installed, both in the well and in the surface facilities to be able to isolate the containment lines for the acid gas injection system into small volumes, even release of small volumes of acid gas can be harmful. Consequently, the operators are required to have a detailed emergency response plan (ERP) if a leak occurs that may impact humans. An emergency planning zone, the EPZ (i.e. area of land which may be impacted by the release of H_2S), is defined around the sour gas facility. The size of the EPZ increases with time as the cumulative amount of acid gas re-injected increases, initially from that in the pipeline to that in the reservoir. However, the EPZ must be kept to a reasonable size (Longworth *et al.*, 1996). To have an effective ERP, the area surrounding the injection site should be equipped with H_2S detection and alarm systems, windsocks, self-contained breathing apparatus, and remote unit and plant shutdown stations.

Subsurface Considerations

The general location for an acid-gas injection well is often influenced by the proximity to sour gas oil or gas production that is the source of acid gas. The actual location is based on a general assessment of the regional geology and hydrogeology, designed to evaluate the potential for leakage (Longworth *et al.*, 1996), which include:

1. size of the injection zone, to confirm that it is large enough to hold all of the injected acid gas over the project lifetime;
2. thickness and extent of the overlying confining layer (caprock), and any stratigraphic traps or fractures that may affect its ability to contain the acid gas;
3. location and extent of the underlying or lateral bounding formations;
4. folding or faulting in the area, and an assessment of seismic risk;
5. flow rate and direction of the natural flow system, to assess the potential for migration of the injected acid gas;
6. permeability and heterogeneity of the injection zone;
7. chemical composition of the formation fluids (water for aquifers, oil or gas for reservoirs);
8. formation temperature and pressure;
9. analyses of formation and caprock core (if available); and, finally,
10. a complete and accurate drilling history of offsetting wells within several km of the injection well, to identify any wells or zones that may be impacted by the injected acid gas.

In addition, the regulatory agencies require that environmental concerns are addressed, such as injection-formation suitability, wellbore integrity, operating parameters (to ensure formation and well integrity), and optimization of the injection space, considered a limited resource. Because of the nature of acid gas injection operations, the wells are considered as Class III disposal wells, unless the acid gas is dissolved in produced water prior to injection, in which case the well is designated as either Class Ib or Class II, depending on the produced-water designation (AEUB, 2000). Completion and logging requirements are similar for Class II and III wells, and include:

- a. all geological zones must be identified using logs and/or core;
- b. all potential hydrocarbon-bearing zones and the shallow potable groundwater aquifers must be hydraulically isolated by cement;
- c. injection must be through tubing, and the annulus must be with a corrosion-inhibiting fluid;
- d. hydraulic isolation and cement integrity must be confirmed by a full-length casing log; and
- e. safety devices must be installed both above the ground and in the well bore to ensure that failure of any component in the system does not result in environmental damage.

If the injection pressure drops for any reason, the well is automatically shut-in, to prevent acid gas backflow.

Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short- and long-term fate of the injected acid gas. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface. These potential pathways are of three types: the caprock pore space (“membrane”), natural and/or induced fractures (“cracks”) through the confining strata, and improperly completed and/or abandoned wells (“punctures”). To avoid diffuse gas migration through the caprock pore space, the difference between the pressure at the top of the injection aquifer or reservoir and the pressure in the confining layer must be less than the *caprock threshold displacement pressure*, which is the pressure needed for the acid gas to overcome the capillarity barrier and displace the water which saturates the caprock pore space. To avoid acid gas migration through fractures, the injection zone must be free of natural fractures, and the injection pressure must be below a certain threshold to ensure that fracturing is not induced. The maximum bottomhole injection pressure is set by regulatory agencies at 90% of the fracturing pressure. In the absence of site-specific tests, the pressures are limited by pressure-depth correlations, based on basin-wide statistical data for the Alberta basin. From this point of view, injection into a depleted oil or gas reservoir has the advantages of injection pressures being low and of wells and pipelines being already in place (Keushnig, 1995).

REVIEW OF OPERATIONS IN ALBERTA

Because the suitability for and approval of acid gas injection operations are determined by the characteristics and containment properties of the injection aquifer or reservoir, which then affect operation and engineering characteristics, the review, subsurface and surface, for the 31 sites in Alberta is summarized in Tables 1 to 6 in the Appendix in the following order. Tables 1 and 2 summarize the aquifer and reservoir geology, rock characteristics and fluids. Table 3 summarizes licensed operating parameters, such as injection pressure, rate and volumes, and the radius of the emergency protection zone (EPZ). The latter is established for the case of an atmospheric release of acid gas, either as a result of an escape to the surface from the injection zone, or as a result of

failure in surface facilities. Tables 4, 5 and 6 summarize engineering characteristics of the acid gas injection operations, such as: injection wells, pipelines, and gas plant compressors, respectively. Common to each table is a site number or plant number. The two designations were necessary because one plant compressor train could serve several injection sites, and at each injection site there could be several injection wells. The plant designation number ends in “00”. The non-zero integers making up the plant number are the group indicator for the sites belonging to that particular plant. For example, plant number 1500 refers to site numbers 1510, 1522, and 1563 in the tables. Lack of data or information in the original applications is denoted in tables by ND (no data). If a data category does not apply to a certain case, such as water salinity for an oil reservoir, then NA (not applicable) is used. Although only 31 acid gas injection sites were licensed up to Fall 2001, Tables 1-3 have 34 lines because: a) at one site the original application was for one formation (site 312) and then, after a period of operation, it was changed to another, deeper formation (site 320), and b) at one site there are actually 3 individual injection wells in different units (sites 1510, 1522 and 1563). Tables 4-6 have more than 34 lines because there are injection sites with multiple wells and pipelines and/or compressors. A series of self-explanatory graphs were produced on the basis of the summary tables, which are grouped into 3 categories: host rock, host fluids and injection operations.

Subsurface Characteristics

The depth of the injection zone varies mostly in the 1100-2100 m range, although in a few cases it is as shallow as 705 m, and as deep as 2918 m (Table 1). The shallow injection zones (i.e. at 705 m, 809 m and 913 m depth) correspond actually to sour water injection. Although the thickness of the injection zone varies between 4 and 276 m, the actual net pay reaches only 100 m. At 23 locations acid gas is injected into a deep saline aquifer, and at 11 sites it is injected into a depleted oil or gas reservoir. Of these, 22 are in carbonate rocks and 12 are in sandstones (Table 1). Shales constitute the overlying confining unit (caprock) in most cases, although tight limestones, evaporates and anhydrites are also present. Their thickness varies between 2 and 270 m. (Table 1). The porosity of the injection zone varies between 4% and 30% (Table 2). The carbonate rocks generally have low porosity, except for carbonate reefs. Only the porosity of sandstone rocks displays a general trend of decreasing porosity with increasing depth. Rock permeability is indicated only in 3 cases: 29.5, 34.5 and 500 mD.

The original formation pressure is generally subhydrostatic with respect to freshwater, which is characteristic of the Alberta basin (Bachu, 1999), and, except for one very low case of 5915 kPa that actually corresponds to a sour water injection operation, varies between 8900 kPa and 28,588 kPa (Table 2). The cases where pressure seems to be slightly above hydrostatic, correspond actually to high salinity formation waters. If the real formation water density is taken into account, then pressure at all sites is hydrostatic or less. In the case of acid gas injection into depleted oil or gas reservoirs, the original reservoir pressure was drawn down as a result of production, such that formation pressure at the start of acid gas injection was less than the original formation pressure (Table 2). Production-induced drawdown occurs also in the case of injection into an aquifer underlying an oil pool, and into an aquifer located very close to an oil pool. In 5 cases formation pressure at start up was below the critical pressure of CO₂.

Formation temperature varies between 47°C at ~1360 m depth and 103°C at ~2800 m depth

(Table 2), although higher temperatures than the lowest are recorded at shallower depth (e.g. 56°C at ~1140 m), and a relatively low temperature (82°C) is indicated for a deep injection zone (~2680 m). The relatively wide spread in temperature variation with depth for the acid-gas injection zones is due to the variability in geothermal gradients across the Alberta basin, which exhibits a trend of increasing gradients from the south, where they are as low as 20°C/km, to the north, where they reach more than 50°C/km (Bachu, 1993).

Generally formation waters are very saline, with salinity varying in a very wide range, from ~56,000 mg/l to ~340,000 mg/l (Table 3). Although there is a broad trend of increasing salinity with depth, exceptions are due to the injection zones being either characterized by fresher water influx, or in the vicinity of evaporitic beds. The very high salinity encountered at a relatively shallow depth corresponds to injection into a carbonate aquifer in eastern Alberta overlain by thick halite beds. For the case of acid gas being injected into depleted oil reservoirs, the oils are medium to very light (33°API to 68°API) (Table 2). This indicates that there is a high probability of the acid gas being miscible with reservoir oil, property that may be used for enhanced oil recovery, as was the case of one of the Zama sites (Davison et al., 1999). Reservoir gases are generally light (specific gravity less than 0.75) except for three cases of 0.915, 1.024 and 1.121 (Table 3). Because acid gas is generally heavier than these reservoir gases, it may be used for enhanced gas recovery.

Licensed Operations

The licensed parameters for the acid gas operations are listed in Table 3. The composition of the acid gas licensed for injection varies between 0.15% CO₂ and 75% H₂S, and 95% CO₂ and 4% H₂S, with C+ gases for the balance. The maximum approved well head injection pressure (WHIP) and bottom hole injection pressure (BHIP) reach 13,000 kPa and 35,800 kPa, respectively. The maximum approved well head pressure (WHIP) is generally lower than the formation pressure except for the few cases where the injection reservoir has been depleted prior to operations start up. The maximum approved bottom hole injection pressure (BHIP) is always higher than the formation pressure to ensure injectivity. Approved daily injection rates vary between 2,800 and 210,000 m³/day, and maximum allowed injection volumes vary between 6·10⁶ and 290·10⁶ m³. Operations lifetime ranges from 10 to 25 years. Emergency planning zones in case of an accidental acid gas escape into the atmosphere vary between as low as 0.48 km and as high as 9 km around the injection well.

Surface Characteristics

Injection well characteristics are listed in Table 4. Depths range from 1,000 to 3,000 metres. Casing diameter ranges from 114 to 244 mm, while the tubing diameter ranges from 60 to 178 mm. The annulus fluid is sealed by a packer and is corrosion inhibited being either fresh water, KCl water, produced water, crude oil, or diesel.

Pipeline characteristics are compiled in Table 5. The pipelines connect the plant compressors to the re-injection wells, and range in length from 0.1 to 5.4 km, with diameters ranging from 60 to 114 mm and wall thicknesses from 4 to 11 mm. Typically, only the shorter pipelines are stainless steel. The majority of the pipelines are mild carbon steel. Currently, stress levels in the pipeline

are less than half the approved levels, and do not exceed 30%, while licensed levels are as high as 61%.

No attempt has been made to compare the sweetening steps for the sour gas stream for the different sites. The comparison starts at the compression stage, where the acid gas stream has been concentrated to a mixture of H_2S and CO_2 , with accessory water vapour and hydrocarbon components. Table 6 summarizes the characteristics of the gas plant compressors. Over 90% of the compressors are electricity driven. Four-stage compression dominates, with power ranging from 50 to 800 HP. In the majority of cases dehydration is supplied by the compression cycle as discussed previously, and only in a few cases either triethylene glycol, refrigeration or a desiccant is used. The maximum approved injection rates of the acid gas stream ranges from 3,000 to 210,000 m^3/day (i.e. flow rates through the compressors), with the highest rates being in carbonate reservoirs. Generally, the rates of injection actually used are close to the maximum approved rates. However, this is not true for the compressor discharge pressures. They are generally more than 25% lower than the maximum approved wellhead injection pressure (WHIP). Maximum wellhead injection pressures range from 4 MPa to 13 MPa. Generally, the compressed acid gas is injected in a pressure-temperature range where the liquid phase is stable, resulting in an appreciable head pressure being generated due to the height of column of this liquid in the wellbore. Assuming the average density of the acid gas liquid is 750 kg/m^3 , a head gradient of approximately 7.5 kPa/m will be generated by the liquid column.

ISSUES

Issues are for the most part environmentally and safety related and need addressing, hence, they directly affect the economics of the process. Either a slow or rapid acid gas leak can result in loss of life or contamination of the bio- and atmosphere leading to degradation of the environment. Surface safety is addressed through engineering, installation of safety valves and monitoring systems, and emergency procedures in case of H_2S leaks. Subsurface issues are of two inter-related categories: the effect of the acid gas on the rock matrix and well cements, and plume containment.

Depending on mineralogy, rock dissolution or precipitation may occur, affecting the porosity and permeability of the host rock. The fact that both CO_2 and H_2S are dissolving in the formation water leads to some complex reaction paths (Gunter *et al.*, 2000; Hitchon *et al.*, 2001) where carbonates precipitate and dissolve, and pyrite/pyrrhotite precipitates. Dissolution of some of the rock matrix in carbonate strata, or of the carbonates surrounding the sand grains in sandstone units results in lower injection pressures in the short term. A major concern with the injection process is the potential for formation damage and reduced injectivity in the vicinity of the acid gas scheme. The reduction in injectivity could be the result of fines migration, precipitation and scale potential, oil or condensate banking and plugging, asphaltene and elemental sulfur deposition, and hydrate plugging (Bennion *et al.* 1996).

Cement compatibility with the acid gas, primarily in the injection well, but also in neighbouring wells, is crucial for safety and containment. For example, a noncarbonate and calcium blend shattered when tested in an acid-gas stream for several weeks (Whatley, 2000). Thus, the compatibility of the acid gas with the cement that bonds the casing to the formation must be tested

at a minimum. While the cement for the newly implemented acid-gas operation can be tested and properly selected prior to drilling, the cements in nearby wells are already in place and their condition is largely unknown. Some of these wells could be quite old, with the cement already in some stage of degradation as a result of brine composition. The acid gas, when reaching these wells, may enhance and speed up the cement degradation, leading to possible leaks through the well annulus and/or along casing.

If the acid gas is injected into the originating or other oil or gas pool, the main concern is the impact on further hydrocarbon recovery from the pool and acid-gas production at the pump, although the operation may prove successful, like the Zama X2X pool (Davison *et al.*, 1999). If the gas mixture is injected into an aquifer, the degree to which it forms a bubble and migrates from the injection well depends on various factors, including pressure and temperature, solubility, interplay between driving forces like buoyancy and aquifer hydrodynamics, and aquifer heterogeneity, which controls gravity override and viscous fingering.

CONCLUSIONS

Acid gas injection has largely been developed into a safe and environmentally-friendly technology. It can be injected as a dry gas or a solution gas depending on the wastewater available. Compared to other options, acid gas injection has less environmental consequences than sulfur recovery (where leaching of the sulfur piles can lead to groundwater contamination) or flaring (which essentially substitutes SO_2 for H_2S in the atmosphere, as well as releasing CO_2). Knowledge of the phase-equilibria and properties of the acid gas is extremely important in designing a safe injection operation, which minimizes corrosion, hydrate formation and cavitation, leading to a dense liquid phase for injection. Both monitoring for gas leaks and corrosion, and plans for mitigation if a leak occurs, are an essential part of the technology.

Equally important for a safe acid gas injection operation is the proper characterization and selection of the subsurface injection zone (reservoir or aquifer). Critical elements are containment and prevention of leakage and/or migration through natural or man-made conduits, such as fractures (“cracks”) and abandoned wells (“punctures”). Maintaining the integrity of the confining aquitard (or caprock), which is subjected to physical and chemical stresses, is essential.

An accounting scheme for net CO_2 stored in an acid gas injection operation has not been approved. However, there are certain important factors to consider. Probably the largest contributor to the net CO_2 stored is the composition of the acid gas and the size of the operation. Fuel switching and efficiency can also play a significant role. In the area of fuel switching, most of the compression is supplied by electricity, which in Alberta is dominantly produced by coal-fired power plants. In an environment where credit for CO_2 emission reduction is sought, gas-fired compressors would be favored, as they have approximately half the CO_2 emissions per unit of energy consumed. The transition would mean that part of the gas plant sweet gas stream would be used to fire the compressors. There are also efficiency savings that can help maximize the net CO_2 injected. Most acid gas injection schemes are run in a pressure-temperature region so that a liquid column of acid gas exists in the wellbore during injection, thus minimizing the compression required for injection. Another saving can be gained by operating the compression cycles so as to condense the water from the acid gas while it is still in the gaseous state, thereby eliminating the

need for dehydrators.

Acid gas injection is more than an industrial, scaled-up analogue for geological storage of CO₂. It is a mature technology and applications of this process are growing in number and size. The experience gained so far in North America, particularly in Canada, can be applied elsewhere in the world. As gas resources become more depleted, even more sour gas will be produced; and therefore we predict that this technology will be resulting in the reduction of significant CO₂ emissions even without the incentive of CO₂ emission trading. With the advent of trading, acid gas injection should become even more appealing to oil and gas producers.

The technology and experience developed in the engineering aspects of acid gas injection operations (i.e., design, materials, leakage prevention and safety) can be easily adopted for large-scale operations for CO₂ geological storage, since a CO₂ stream with no H₂S is less corrosive and dangerous. Although the fate of the injected acid gas has not been monitored to date, the subsurface information about aquifer and reservoir rocks and fluids may provide a wealth of information as to what characteristics a good CO₂-sequestration site should have. This information can be used for the screening and identification of future sites for the geological sequestration and storage of CO₂. In addition, monitoring the fate of the injected acid gas at one or more such sites will provide invaluable information about the long term fate of injected acid and greenhouse gases.

Finally, H₂S, like CH₄, is a valuable energy source. Besides hydrocarbons, sulfur and H₂S represent the only additional store of chemical energy that occurs naturally on Earth in substantial quantity (Connock, 2001). Just as CH₄ is oxidized to CO₂ to recover energy, oxidation of H₂S to SO₂ can provide energy. If technology can be developed to make this economically attractive, then the acid gas components for injection would become CO₂ and SO₂ instead of CO₂ and H₂S (Connock, 2001).

REFERENCES

- AEUB (Alberta Energy and Utilities Board) 2000. *Guide 65: Resources Applications Guide*. Alberta Energy and Utilities Board, Calgary, AB, 113-136.
- BACHU, S. 1993. Basement heat flow in the Western Canada Sedimentary Basin: Tectonophysics, **222:1**, 119-133.
- BACHU, S. 1999. Flow systems in the Alberta Basin: Patterns, types and driving mechanisms. *Bulletin of Canadian Petroleum Geology*, **47**, 455-474.
- BACHU, S. 2000. Sequestration of carbon dioxide in geological media: criteria and approach for site selection. *Energy Conversion and Management*, **41:9**, 953-970.
- BACHU, S. & STEWART, S. 2002. Geological sequestration of anthropogenic carbon dioxide in the Western Canada Sedimentary Basin. *Journal of Canadian Petroleum Technology*, **41:2**, 32-40.
- BENNION, D.B., THOMAS, F.B., BENNION D.W. & BIETZ, R.F. 1996. Formation screening to minimize permeability impairment associated with acid gas or sour gas injection/disposal. *CIM Paper 96-93 Presented at the 47th Annual Technical Meeting of the CIM Petroleum Society*, Calgary, AB, June 10-12, 1996.
- CARROLL, J.J. & LUI, D.W. 1997 Density, phase behavior keys to acid gas injection. *Oil and Gas Journal*, June 23, 63-72.
- CLARK, M.A., SYREK, W.Y., MONNERY, W.D., JAMALUDDIN, A.K.M., BENNION, D.B., THOMAS, F.B., WICHERT, E., REED, A.E. & JOHNSON, D.J. 1998 Designing an optimized injection strategy for acid gas disposal without dehydration. *In: Proceedings of the Seventy-Seventh Gas Processors Association Annual Convention*, Tulsa, OK, 49-56.
- CONNOCK, L. 2001. Acid gas re-injection reduces sulfur burden. *Sulfur*, **272**, 35-41.
- DAVISON, R. J., MAYDER, A., HLADIUK, D. W. & JARRELL, J. 1999. Zama acid gas disposal/miscible flood implementation and results. *Journal of Canadian Petroleum Technology*, **38:2**, 45-54.
- GUNTER, W.D., PERKINS, E.H. & HUTCHEON, I. 2000. Aquifer disposal of acid gases: modeling of water-rock reactions for trapping acid wastes. *Applied Geochemistry*, **15**, 1085-1095.
- HITCHON, B., PERKINS, E.H. & GUNTER, W.D. 2001. Recovery of trace metals in formation waters using acid gases from natural gas. *Applied Geochemistry*, **16**, 1481-1497.
- KEUSHNIG, H. 1995. Hydrogen sulphide – if you don't like it, put it back. *Journal of Canadian Petroleum Technology*, **34:6**, 18-20.
- KOPPERSON, D., HORNE, S., KOHN, G., ROMANSKY, D., CHAN, C. & DUGWORTH, G.L. 1998a. Injecting acid gas with water creates new disposal option. *Oil & Gas Journal*, **96:31**, 33-37.
- KOPPERSON, D., HORNE, S., KOHN, G., ROMANSKY, D., CHAN, C. & DUGWORTH, G.L. 1998b. Two cases illustrate acid gas/water injection scheme. *Oil & Gas Journal*, **96:32**, 64-70.
- HO, K. T., MCMULLEN, J., BOYLE, P., ROJEK, O., FORGO, M. & BEATTY, T. 1996. Subsurface acid gas disposal scheme in Wayne-Rosedale, Alberta. *SPE Paper 35848, In: Proceedings of the Gas Technology Symposium*, Calgary, AB, Canada, 28 April – 1 May 1996, SPE, 699-704.

- LOCK, B.W. 1997. Acid gas disposal – A field perspective. *In: Proceedings of the Seventy-Sixth Gas Processors Association Annual Convention*, San Antonio, TX, March 10-12, 1999, Tulsa, OK, p. 161-170.
- LONGWORTH, H. L., DUNN, G. C. & SEMCHUK, M. 1996. Underground disposal of acid gas in Alberta, Canada: regulatory concerns and case histories. *SPE Paper 35584, In: Proceedings of the Gas Technology Symposium*, Calgary, AB, Canada, 28 April – 1 May 1996, SPE, 181-192.
- NG, H-J., CARROLL, J. J. & MADDOCKS, J. R. 1999. Impact of thermophysical properties research on acid gas injection process design. *In: Proceedings of the Seventy-Eighth Gas Processors Association Annual Convention*, Nashville, TN, March 1-3, 1999, Tulsa, OK, 114-120.
- WHATLEY, L. 2000. Acid-gas injection proves economic for west-Texas plant. *Oil & Gas Journal*, **98:21**, 58-61.
- WICHERT, E. & ROYAN, T. 1996. Sulfur disposal by acid gas injection. *SPE Paper 35585, In: Proceedings of the Gas Technology Symposium*, Calgary, AB, Canada, 28 April – 1 May 1996, SPE, 193-200.

Appendix

Acid Gas Injection Operations in Alberta, Canada

Appendix Tables

1. Reservoir Geology
2. Reservoir Properties and Fluids
3. Licensed Injection Operations
4. Acid Gas Injection Wells
5. Pipelines
6. Gas Plant Compressors

Appendix Graphs

- ♦ Host Rock Graphs
- ♦ Host Fluids Graphs
- ♦ Injection Operations Graphs

Table 1: Reservoir Geology

Site No.	Injection into	Injection Formation					Caprock Formation			Underlying Formation		
		Inj. Zone Depth	Name	Lithology	Thk (m)	Net Pay	Name	Lithology	Thk (m)	Name	Lithology	Thk (m)
312	Oil & Gas Reservoir	1552 - 1556	Halfway Fm	Qtz-Sandstone	4	4	Charlie Lake Fm	Sandstone	101	Doig Fm	Shaly Siltstone	79
320	Water Aquifer	1905 - 1942	Belloy Fm	Sandstone	37	13	Montney Fm	Siltstone	250	Taylor Flat Fm	Sandstone	396
449	Water Aquifer	2715 - 2918	Wabamun Gp	Limestone	203	10	Exshaw Fm	Shale	130	Graminia Fm	Siltstone	10
581	Water Aquifer	2285 - 2503	Wabamun Gp	Limestone	218	10	Exshaw Fm	Shale	130	Graminia Fm	Arg.-silty Carb.	7
625	Oil Reservoir	1422 - 1439	Ellerslie Mbr	Sandstone	17	17	Ellerslie Mbr	Shale	12	Ellerslie Mbr	Shale	14
718	Water Aquifer	705 - 981	Wabamun-Winterburn	Limestone	276	100	Exshaw Fm	Shale	10	Winterburn Gp	Limestone	ND
844	Water Aquifer	2222 - 2228	Wabamun Gp	Limestone	6	8	Banff Fm	Limestone	190	Blueridge Mbr	Dolomitic Shale	50
997	Oil Reservoir	1391 - 1401	Halfway Fm	Sandstone	10	ND	Charlie Lake Fm	Anhydrite	15	Doig Fm	Shaly Siltstone	25
1034	Oil Reservoir	2677 - 2695	Leduc Fm	Dolostone	18	18	Ireton Fm	Shale	18	Cooking Lake Fm	Carbonates	85
1189	Oil & Gas Reservoir	1541 - 1562	Nordeg Mbr	Sandstone	21	6	Lower Mannville Fm	Shale	15	Pekisko-Banff	Dolomitic Shale	15
1242	Oil Reservoir	1745 - 1840	Wabamun Gp	Dolostone	95	88	Exshaw Fm	Shale	10	None Identified	Carbonates	50
1396	Oil Reservoir	1927 - 2058	Wabamun Gp	Dolostone	131	50	Exshaw Fm	Shale	8	None Identified	ND	ND
1489	Gas Reservoir	1355 - 1390	Kiskatinaw Fm	Qtz-Arenite	35	8	Belloy & Kiskatinaw	Anhydrite	85	Golata Fm	Shale	21
1510	Water Reservoir	1493 - ND	Keg River Fm	Dolostone	ND	ND	Muskeg Fm	Evaporites	270	None Identified	ND	ND
1522	Gas Reservoir	1317 - 1385	Slave Point Fm	Limestone	68	8	Fort Simpson Fm	Shale	13	Fort Vermilion Mbr	Anhydrite	15
1563	Oil & Gas Reservoir	1478 - 1585	Zama & Keg River	Carbonates	107	25	Muskeg Fm	Anhydrite	75	Lower Keg River	Carbonates	45
1630	Water Aquifer	1661 - 1673	Belloy Fm	Sandstone	12	10	Montney Fm	Shale	240	Debolt Fm	Dolostone	ND
1734	Water Reservoir	1200 - ND	Leduc Fm	Dolostone	ND	30	Ireton Fm	Shale	22	None Identified	ND	ND
1895	Water Aquifer	1110 - 1166	Keg River Fm	Dolostone	56	18	Muskeg Fm	Evaporites	150	Chinchaga Fm	Anhydrite	35
1971	Water Aquifer	1167 - ND	Wabamun Gp	Limestone	ND	16	Ellerslie-Wabamun	Lime Mudstone	7	Graminia-Blueridge	Shaly Siltstone	ND
2081	Water Aquifer	1958 - ND	Beaverhill Lake Gp	Dol. Limestone	ND	10	Leduc-Cooking Lake	Lime Mudstone	150	None Identified	ND	ND
2101	Water Aquifer	1373 - 1454	Keg River Fm	Dolostone	81	81	Muskeg Fm	Anhydrite	140	Chinchaga Fm	Anhydrite	35
2271	Water Aquifer	1601 - 1650	Keg River Fm	Dolostone	49	15	Muskeg Fm	Evaporites	85	Lower Keg River	Dolostone	ND

Site No.	Injection into	Injection Formation				Caprock Formation			Underlying Formation			
		Inj. Zone Depth	Name	Lithology	Thk (m)	Net Pay	Name	Lithology	Thk (m)	Name	Lithology	Thk (m)
2469	Water Reservoir	ND - ND	None Identified	ND	ND	ND	None Identified	ND	ND	None Identified	ND	ND
2573	Water Aquifer	1341 - 1453	Upper Leduc	Dolostone	112	40	Nisku Fm	Dolostone	20	Lower Ireton	Shale	10
2636	Water Aquifer	2781 - 2847	Wabamun Gp	Dolostone	66	60	Banff Fm	Limestone	168	Wabamun-Winterbu	Limestone	90
2719	Water Aquifer	2036 - 2118	Belloy Fm	siliciclastics & c	82	10	Montney Fm	Shaly Siltstone	250	Taylor Flat Fm	carbonate-rich s	70
2830	Water Aquifer	1416 - 1433	Keg River Fm	Dolostone	17	10	Prairie Evaporite Fm	Salt	185	Cambrian System	Clastics	ND
2982	Water Aquifer	1589 - 1610	Belloy Fm	Sandstone	21	29	Montney Fm	Shale	264	Stoddart Gp	Carbonates	ND
3084	Water Aquifer	2010 - 2090	Cooking Lake Fm	Limestone	80	40	Duvernay Fm	Shale	42	Mildred Mbr	Limestone	51
3195	Water Aquifer	1880 - 1934	Leduc Fm	Dolostone	54	5	Ireton Shale	Shale	2	Waterways Fm	Shale	ND
3340	Water Aquifer	1182 - 1286	Ostracod-Basal Qtz	Sandstone	104	3	None Identified	ND	ND	None Identified	ND	ND
3465	Water Aquifer	913 - 984	Basal Quartz Sd	Clastics	71	ND	None Identified	ND	ND	None Identified	ND	ND
3581	Oil Reservoir	809 - 838	Cummings Mbr	Sandstone	29	ND	Lloydminster Mbr	Sandstone	ND	Woodbend Gp	Carbonates	ND

Table 2: Reservoir Properties and Fluids

Site No.	Porosity (fraction)	Permeability (md)	Formation Temperature (°C)	Formation Pressure		Reservoir volume (1000 m³)	Formation Water				Oil API gravity	Produced Gas	
				Original (kPa)	Startup (kPa)		TDS (mg/l)	Na (mg/l)	Ca (mg/l)	HCO ₃ (mg/l)		Specific gravity	Molecular mass
312	ND	ND	68	15200	NA	ND	ND	ND	ND	ND	37.3	0.712	20.62
320	0.12	29.5	76	16700	ND	610	162000	53400	4760	471	NA	NA	NA
449	0.064	ND	ND	27000	ND	569.3	152813	41530	9830	481	NA	NA	NA
581	0.08	34.5	70	20244	ND	320	ND	ND	ND	ND	NA	NA	NA
625	0.15	50	60	10245	NA	539	69400	23200	2880	397	ND	0.684	19.8
718	0.1	ND	ND	5915	ND	ND	ND	21605	5756	292.8	NA	NA	NA
844	0.2	ND	69	17762	ND	107	ND	ND	ND	ND	NA	NA	NA
997	0.12	ND	60	12800	9500	ND	ND	9289	340.8	868.6	ND	0.7022	20.34
1034	0.16	ND	82	28588	NA	74.4	ND	ND	ND	ND	37	0.742	21.5
1189	ND	ND	58	12135	4215	1631	55830	16850	3964	105	ND	0.669	ND
1242	0.05	ND	58	17982	NA	52.436	ND	ND	ND	ND	56.6	NA	NA
1396	0.05	ND	63	20317	NA	114.95	ND	ND	ND	ND	33.4	NA	NA
1489	0.21	500	47	13035	NA	182	156722	52095	5485	278	NA	ND	ND
1510	0.06	ND	78.7	15000	5842	341.5	ND	ND	ND	ND	35.2	NA	NA
1522	0.08	ND	49	13394	3110	ND	ND	ND	ND	ND	NA	ND	ND
1563	0.04	ND	76	14479	13394	225	168355	48600	11400	1435	36.15	0.691	20
1630	0.18	ND	57	16700	12855	395.5	153804	54500	5240	257	NA	0.604	17.5
1734	0.1	ND	53	ND	9465	136.67	120000	27100	11100	771	68.1	0.73	21.1
1895	0.05	ND	56	11164	ND	308	266000	ND	ND	ND	NA	NA	NA
1971	0.13	ND	45	8900	ND	201.37	ND	ND	ND	ND	NA	NA	NA
2081	0.07	ND	70.5	15700	15700	671	ND	ND	ND	ND	NA	NA	NA
2101	0.04	ND	52	11292	ND	226	ND	ND	ND	ND	NA	NA	NA

Site No.	Porosity (fraction)	Permeability (md)	Formation Temperature (°C)	Formation Pressure		Reservoir volume (1000 m³)	Formation Water				Oil	Produced Gas	
				Original (kPa)	Startup (kPa)		TDS (mg/l)	Na (mg/l)	Ca (mg/l)	HCO ₃ (mg/l)	API gravity	Specific gravity	Molecular mass
2271	0.05	ND	57.7	13237	13237	1300	135000	ND	ND	ND	NA	NA	NA
2469	ND	ND	ND	ND	NA	ND	106618	32600	4510	552	NA	1.121	NA
2573	0.22	ND	35	ND	7500	5084	78924	24330	3160	971	NA	1.024	NA
2636	0.09	ND	103	24680	ND	306.9	ND	ND	ND	ND	NA	NA	NA
2719	0.12	ND	76	20000	ND	330	140000	ND	ND	ND	NA	0.62	36.79
2830	0.06	ND	38	13790	ND	240.8	341430	106920	21976	126	NA	NA	NA
2982	0.2	ND	60	13744	ND	209	156804	54500	5240	257	NA	0.604	17.5
3084	0.05	ND	70	ND	15459	480.9	222663	48930	30968	166	51.5	0.65	18.8
3195	0.06	ND	65	ND	15500	415.8	122449	30200	11100	895	NA	0.915	26.5
3340	0.16	ND	50.6	9300	1700	ND	ND	ND	ND	ND	NA	0.693	20.45
3465	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	NA	NA	NA
3581	0.3	ND	ND	ND	5200	230	ND	ND	ND	ND	ND	NA	NA

Table 3: Licensed Operations

Site No.	Licensed Inj. Gas		Maximum Approved		Max. Approved Injection Rate (1000 m ³ /d)	Total Approved Inj. Volume (1000 m ³)	Life time (years)	EPZ (km)
	CO ₂ (mol frac)	H ₂ S (mol frac)	BHIP (kPa)	WHIP (kPa)				
312	0.25	0.75	14910	5000	27	34500	10	3
320	0.32	0.66	22000	8000	60	263000	15	3.5
449	0.15	0.75	33000	12000	30	63000	ND	5.3
581	0.79	0.20	35800	13000	34	124100	10	3.3
625	0.57	0.42	10546	9000	58	213000	20	ND
718	0.31	0.01	8596	3750	6	6000	ND	0.04
844	0.65	0.35	20300	10500	16	38000	15	2.4
997	0.44	0.34	26000	13000	4.2	16000	10	1.07
1034	0.31	0.63	31380	12300	12	40000	25	5.5
1189	0.95	0.04	11000	7500	40	70000	15	0.43
1242	0.29	0.67	21500	9000	2.8	8100	20	3.7
1396	0.45	0.52	20303	12000	18	35000	11	5
1489	0.57	0.41	7500	7100	5	18700	25	3.7
1510	0.70	0.30	16707	12000	210	88000	ND	1.7
1522	0.70	0.30	21000	11000	210	22000	ND	3.04
1563	0.61	0.38	14500	12000	160	157000	8	17
1630	0.70	0.30	17982	10000	21	94200	15	1.3
1734	0.87	0.13	ND	9000	35	64000	15	ND
1895	0.34	0.64	11500	7000	42	140000	15	2
1971	0.80	0.17	18220	9800	11	41000	10	2
2081	0.50	0.48	21760	11700	40	185100	15	2.85
2101	0.34	0.64	18925	7600	26.3	106000	15	3.75
2271	0.75	0.25	18192	9500	74.6	290000	15	3.2
2469	0.50	0.50	ND	8273	ND	ND	ND	ND
2573	0.70	0.17	ND	8000	35	41000	ND	1.5
2636	0.45	0.55	ND	10500	28	109000	ND	ND
2719	0.51	0.49	24607	9000	27	150000	20	5
2830	0.88	0.09	22000	10000	24	86000	12	1.2
2982	0.71	0.25	14210	9000	21	58200	15	2.2
3084	0.72	0.25	20000	10000	25	115000	15	1.9
3195	0.82	0.17	20000	10000	28	140000	15	0.95
3340	0.83	0.15	ND	6000	ND	ND	ND	ND
3465	0.60	0.13	ND	11000	ND	ND	ND	ND
3581	0.70	0.30	6700	ND	12	16000	ND	ND

Table 4: Acid Gas Injection Wells

Site No.	Well Number	Production Casing			Production Tubing			Type of Fluid in the Annulus	Packer Depth (m KB)
		Depth (m KB)	Size (mm)	Density (kg/m)	Size (mm)	Density (kg/m)	Grade		
312	143013	2286.2	139.7	23.1	60.3	6.99	J-55	Inhibited crude oil	1540
320	263792	1942	139.7	30	60.3	6.99	J-55	Inhibited H2O	1900
449	205662	2947	177.8	54	73	9.67	J-55	Inhibited crude oil	2720
581	151636	ND	177.8	39	73	9.67	J-55	Fresh H2O, inhibited	2290
625	138139	1658	139.7	23	60.3	6.99	ND	KCl water, inhibited	1628
718	142129	ND	244	ND	140	20.83	S0055	ND	666
844	260595	2295	140	25.3	73	9.67	L-80	ND	2200
997	154078	ND	140	23.1	73	ND	ND	ND	1388
	164367	1425	140	23.1	73	9.67	J-55	ND	1390
	188894	1445	140	23.1	73	9.67	ND	ND	1401
1034	108999	ND	177.8	38.7	60.3	6.99	J-55	Fresh H2O, inhibited	2670
1189	90706	ND	139.7	20.3	73	9.67	J-55	Fresh H2O, inhibited	1531
1242	178540	ND	139.7	25.3	60.3	6.99	J-55	Produced H2O, inhibited	1733
1396	170753	ND	139.7	25.3	60.3	6.99	J-55	Fresh H2O, inhibited	1931
1489	209673	1419.7	139.7	25.3	60.3	6.99	J-55	Diesel	1360
1510	128598	1490	178	34.2	73	9.67	L-80	ND	1487
1522	128595	1524.6	177.8	29.76	73	9.67	L-80	Fresh H2O, inhibited	1300
	280511	ND	178	38.7	73	9.67	L-80	Fresh H2O, inhibited	1322
1563	179488	1495	177.8	39	60.3	6.99	J-55	Diesel	1484
	184266	ND	114	15.6	60	6.99	J-55	ND	ND
1630	221341	ND	177.8	57	73	9.67	ND	3%KCl, inhibited H2O	1663
1734	194384	1225	139.7	20.8	73	9.67	L-80	Inhibited crude oil	1218
1895	266164	1172	177.8	34.23	60.3	6.99	L-80	Inhibited Diesel	1086
1971	278209	1199	114	17	60.3	6.99	L-80	Water	1166
2081	260661	1993	177.8	34.3	73	9.67	L-80	Inhibited H2O	1938
2101	280608	1475	139.7	25.3	60.3	6.99	L-80	Fresh H2O, inhibited	1393
2271	235982	1600.5	139.7	25	73	9.67	J-55	Fresh H2O, inhibited	1582
2469	88409	ND	ND	ND	ND	ND	ND	ND	408
	88471	ND	ND	ND	ND	ND	ND	ND	386
	88516	ND	ND	ND	ND	ND	ND	ND	359
	88589	ND	ND	ND	ND	ND	ND	ND	371
	88612	ND	ND	ND	ND	ND	ND	ND	371
	88621	1046	244	53.57	178	29.3	K-55	ND	1027
	88629	ND	ND	ND	ND	ND	ND	ND	371

Site No.	Well Number	Production Casing			Production Tubing			Type of Fluid in the Annulus	Packer Depth (m KB)
		Depth (m KB)	Size (mm)	Density (kg/m)	Size (mm)	Density (kg/m)	Grade		
2469	88636	ND	ND	ND	ND	ND	ND	ND	398
	88645	ND	ND	ND	ND	ND	ND	ND	354
	88659	ND	ND	ND	ND	ND	ND	ND	371
	88670	1039	244	53.57	178	29.76	K-55	ND	1019
	88674	ND	ND	ND	ND	ND	ND	ND	371
	88686	ND	ND	ND	ND	ND	ND	ND	371
	88727	1018	244	53.57	178	29.76	K-55	ND	968
	88731	1055.1	244	53.57	178	29.76	K-55	ND	999
	88748	ND	ND	ND	ND	ND	ND	ND	366
	89961	931.4	244	53.57	168	29.8	ND	ND	988
	89967	1074.4	244	53.57	178	29.3	K-55	ND	1012
	89973	ND	ND	ND	ND	ND	ND	ND	371
	89997	ND	ND	ND	ND	ND	ND	ND	371
	90041	ND	ND	ND	ND	ND	ND	ND	371
	90053	ND	ND	ND	ND	ND	ND	ND	371
	90070	ND	ND	ND	ND	ND	ND	ND	399
	90074	ND	ND	ND	ND	ND	ND	ND	392
	90105	1034.2	178	29.76	140	20.83	J-55	ND	988
	90130	ND	ND	ND	ND	ND	ND	ND	371
	90168	ND	ND	ND	ND	ND	ND	ND	371
	90196	ND	ND	ND	ND	ND	ND	ND	371
	90208	ND	ND	ND	ND	ND	ND	ND	371
	90229	1033.7	244	53.57	178	29.76	K-55	ND	1010
	90273	1027.6	244	53.57	178	29.3	K-55	ND	1014
	90281	ND	ND	ND	ND	ND	ND	ND	344
	90297	ND	ND	ND	ND	ND	ND	ND	371
	90301	ND	ND	ND	ND	ND	ND	ND	371
	90306	1089.8	244	53.57	178	29.76	K-55	ND	1017
	90342	ND	ND	ND	ND	ND	ND	ND	90342
	90352	ND	ND	ND	ND	ND	ND	ND	317
	90356	1010	244	ND	178	29.76	K-55	ND	1006
	90361	1068.3	244	ND	178	29.76	K-55	ND	1020
	91440	ND	ND	ND	ND	ND	ND	ND	399
	91461	1037	244	53.57	178	29.76	K-55	ND	1024
	91496	ND	ND	ND	ND	ND	ND	ND	395
	91544	ND	ND	ND	ND	ND	ND	ND	ND

Site No.	Well Number	Production Casing			Production Tubing			Type of Fluid in the Annulus	Packer Depth (m KB)
		Depth (m KB)	Size (mm)	Density (kg/m)	Size (mm)	Density (kg/m)	Grade		
2469	91554	1086.6	244	53.57	178	29.76	K-55	ND	1085
	91566	1042	244	53.95	140	20.9	J-55	ND	1023
	91636	ND	ND	ND	ND	ND	ND	ND	409
	91637	1075.9	178	29.76	140	20.8	J-55	ND	1053
	152071	1019.8	244	54	178	29.8	K-55	ND	1001
	162252	1009.21	244	53.7	178	29.3	K-55	ND	ND
2573	204185	1343.9	177.8	56	73	14.14	J-55	Water	1324
2636	290514	2957	139.7	25.3	73	9.67	L-80	Fresh H2O, inhibited	2768
2719	263896	2145	139.7	29.8	60.3	6.99	L-80	Fresh H2O, inhibited	2030
2830	204006	1500	177.8	30	73	9.67	L-80	Inhibited crude oil	1424
2982	221031	ND	139.7	23.07	73	9.67	K-55	Inhibited crude oil	1598
3084	228593	2124	139.7	20	60	ND	J-55	ND	2005
3195	202360	1996	177.8	34.2	73	9.67	L-80	KCl water, inhibited	1879
3340	83493	1365	177.8	34	73	9.67	J-55	ND	1175
3465	55392	ND	ND	ND	ND	ND	ND	ND	912
	55409	ND	ND	ND	ND	ND	ND	ND	922
	55412	ND	ND	ND	ND	ND	ND	ND	915
	55457	ND	ND	ND	ND	ND	ND	ND	912
	55466	ND	ND	ND	ND	ND	ND	ND	917
	55480	ND	ND	ND	ND	ND	ND	ND	901
	55493	ND	ND	ND	ND	ND	ND	ND	905
	55526	ND	ND	ND	ND	ND	ND	ND	893
	55553	ND	ND	ND	ND	ND	ND	ND	906
	55591	ND	ND	ND	ND	ND	ND	ND	891
	55615	ND	ND	ND	ND	ND	ND	ND	894
	55647	ND	ND	ND	ND	ND	ND	ND	898
	55649	ND	ND	ND	ND	ND	ND	ND	ND
	150266	ND	ND	ND	ND	ND	ND	ND	946
	150267	ND	ND	ND	ND	ND	ND	ND	950
	175435	ND	ND	ND	ND	ND	ND	ND	960
	194314	ND	ND	ND	ND	ND	ND	ND	937
3581	52915	856	ND	ND	ND	ND	ND	ND	ND
	186679	987	ND	ND	ND	ND	ND	ND	ND

Table 5: Pipelines

Site No.	Pipeline Length (m)	Pipe Grade	Pipe Outside Diameter (mm)	Pipe Wall Thickness (mm)	Max Operating Pressure (kPa)	Max Allowable Stress Level (%)
312	2250	259	ND	ND	ND	ND
320	ND	ND	ND	ND	ND	ND
449	420	316 SS	48.3	3.68	12800	49
581	3480	359	88.9	4.8	13000	33.5
625	500	B	88.9	11.13	13960	23
718	ND	ND	ND	ND	ND	ND
844	ND	ND	ND	ND	ND	ND
997	ND	ND	ND	ND	ND	ND
1034	150	316 SS	60.3	5.54	11380	36
1189	1460	290	88.9	4.78	8280	27
1242	600	304 SS	60.3	5.54	14240	38
1396	ND	ND	ND	ND	ND	ND
1489	3000	290	60.3	4.8	13790	30
1510	5450	359	88.9	4	12400	38
1522	450	359	88.9	4.8	12400	32
	810	359	88.9	4	12400	38
1563	190	359	88.9	4	14890	46
	4300	359	88.9	4	14890	46
1630	130	Sch 160	60.3	8.74	17250	25
1734	100	316L SS	88.9	5.4	10340	27
1895	1050	290	60.3	3.2	9930	32
1971	ND	ND	ND	ND	13000	ND
2081	ND	316L SS	60.3	ND	16500	ND
2101	800	304 SS	60.3	3.91	10500	48
2271	200	290	114.3	4	12400	61
2469	ND	ND	ND	ND	ND	ND
2573	200	SS	60.3	5.54	9075	ND
2636	650	359	60.3	4.8	10800	19
2719	ND	ND	ND	ND	ND	ND
2830	ND	ND	ND	ND	ND	ND
2982	ND	ND	ND	ND	ND	ND
3084	ND	ND	ND	ND	ND	ND
3195	ND	ND	ND	ND	ND	ND
3340	2200	290	60.3	3.9	7000	19

Site No.	Pipeline Length (m)	Pipe Grade	Pipe Outside Diameter (mm)	Pipe Wall Thickness (mm)	Max Operating Pressure (kPa)	Max Allowable Stress Level (%)
3465	ND	ND	ND	ND	ND	ND
3581	ND	ND	ND	ND	ND	ND

Table 6: Gas Plant Compressors

Plant No.	Manufacturer	Driver Type	HP Rating	No. of stages	Design Rate (1000 m ³ /d)	Discharge Pressure (kPa)	Dehydration Method
300	ND	ND	ND	ND	ND	ND	Refrigeration
400	Ariel	Electric	200	4	30	7250	None
500	ND	Electric	ND	4	ND	ND	Refrigeration
600	ND	Electric	300	4	ND	5600	None
700	ND	ND	ND	ND	ND	ND	ND
800	ND	ND	ND	ND	ND	ND	ND
900	ND	ND	ND	ND	ND	ND	ND
1000	ND	ND	ND	ND	ND	ND	ND
1100	Knox Western	Electric	300	4	36	4400	TEG
1200	Ariel	Electric	50	4	ND	6820	None
1300	Ariel	Electric	250	4	23	8330	None
1400	Ariel	Electric	150	4	7	8350	Dry Desiccation
1500	Ariel	Natural Gas	617	5	105	7550	None
1500	ND	Electric	560	4	84	8700	None
1600	ND	Electric	300	4	ND	5500	Refrigeration
1700	Ariel	Electric	350	4	30	5800	TEG
1800	ND	ND	ND	4	ND	ND	None
1900	ND	Electric	150	4	14	6840	None
2000	ND	ND	ND	4	ND	8000	None
2100	Ariel	Electric	250	4	26	4100	None
2200	ND	ND	ND	5	ND	ND	TEG
2400	ND	ND	ND	ND	ND	ND	ND
2500	Dresser Rand	Electric	800	ND	ND	ND	ND
2600	ND	ND	ND	ND	ND	ND	ND
2700	ND	ND	ND	ND	ND	ND	ND
2800	ND	Electric	300	4	ND	6100	None
2900	ND	ND	ND	ND	ND	ND	ND
3000	ND	ND	ND	ND	ND	ND	ND
3100	ND	ND	ND	ND	ND	ND	ND
3300	ND	Electric	200	4	15	2800	TEG
3400	ND	ND	ND	ND	ND	ND	ND
3500	ND	ND	ND	ND	ND	ND	ND

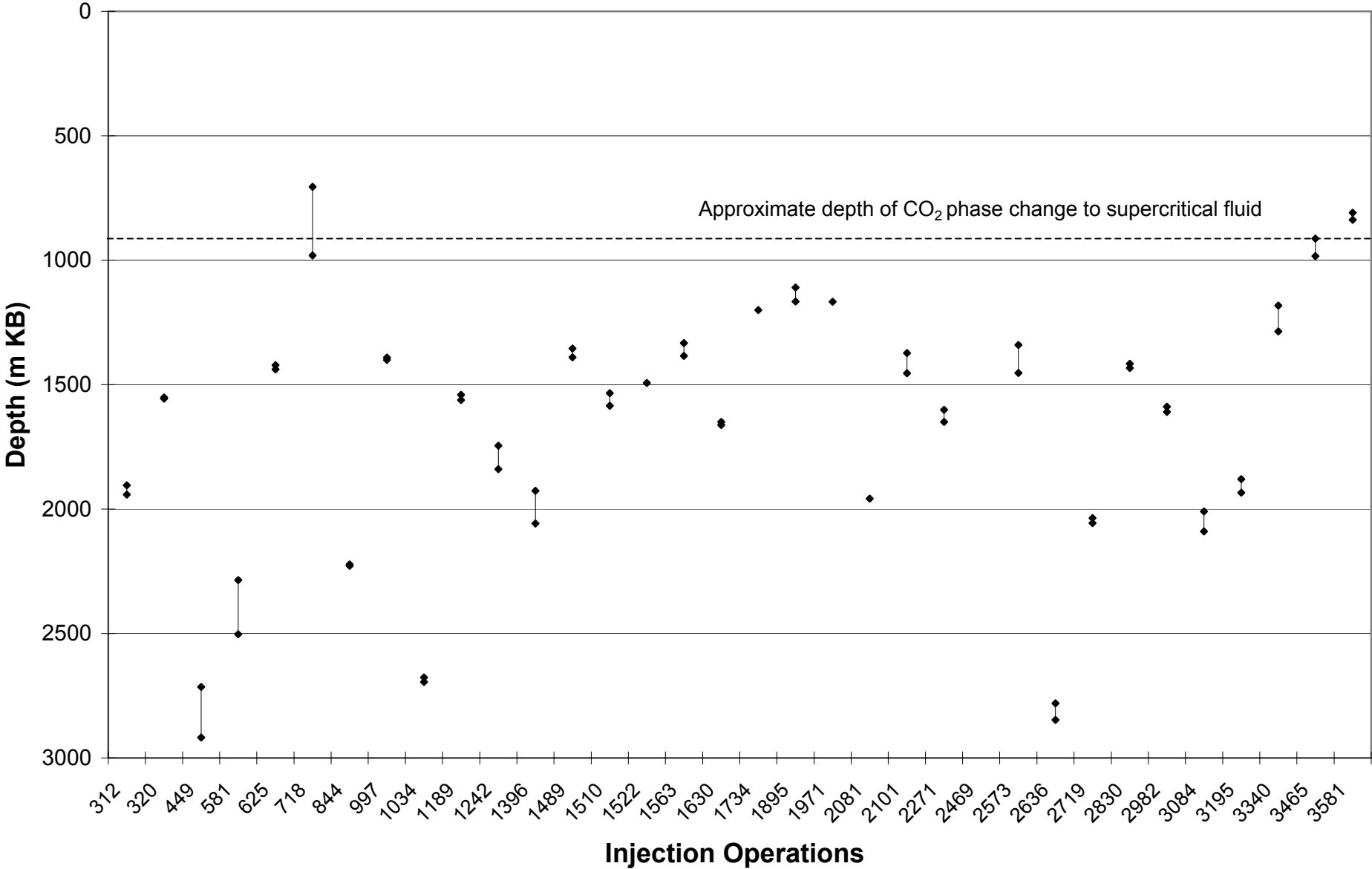
Appendix

Acid Gas Injection Operations in Alberta, Canada

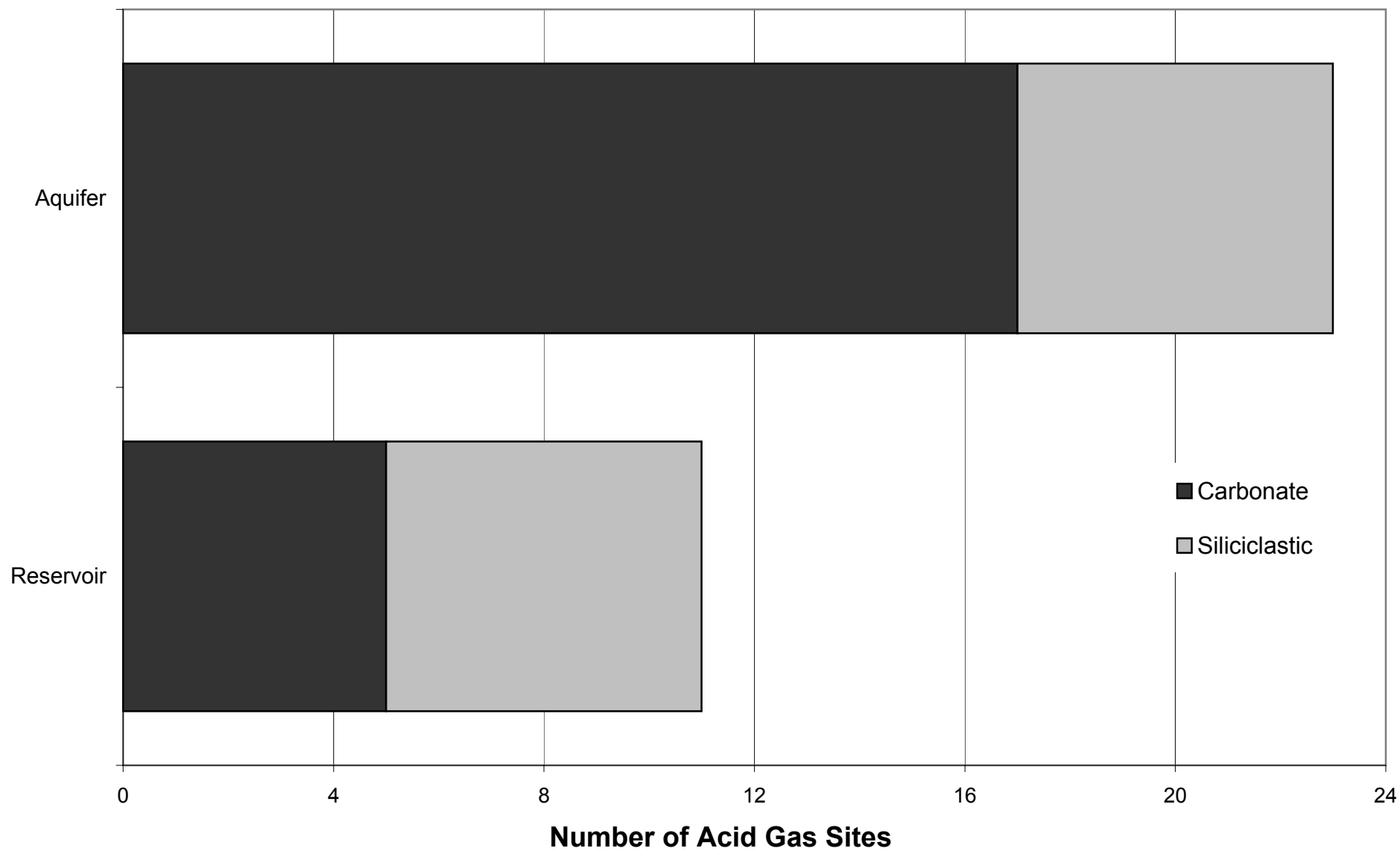
Host Rock Graphs

- ♦ Injection Interval Depths
- ♦ Injection Reservoir Type and Lithology
- ♦ Net Pay of Injection Reservoir
- ♦ Porosity vs. Depth of Host Rock

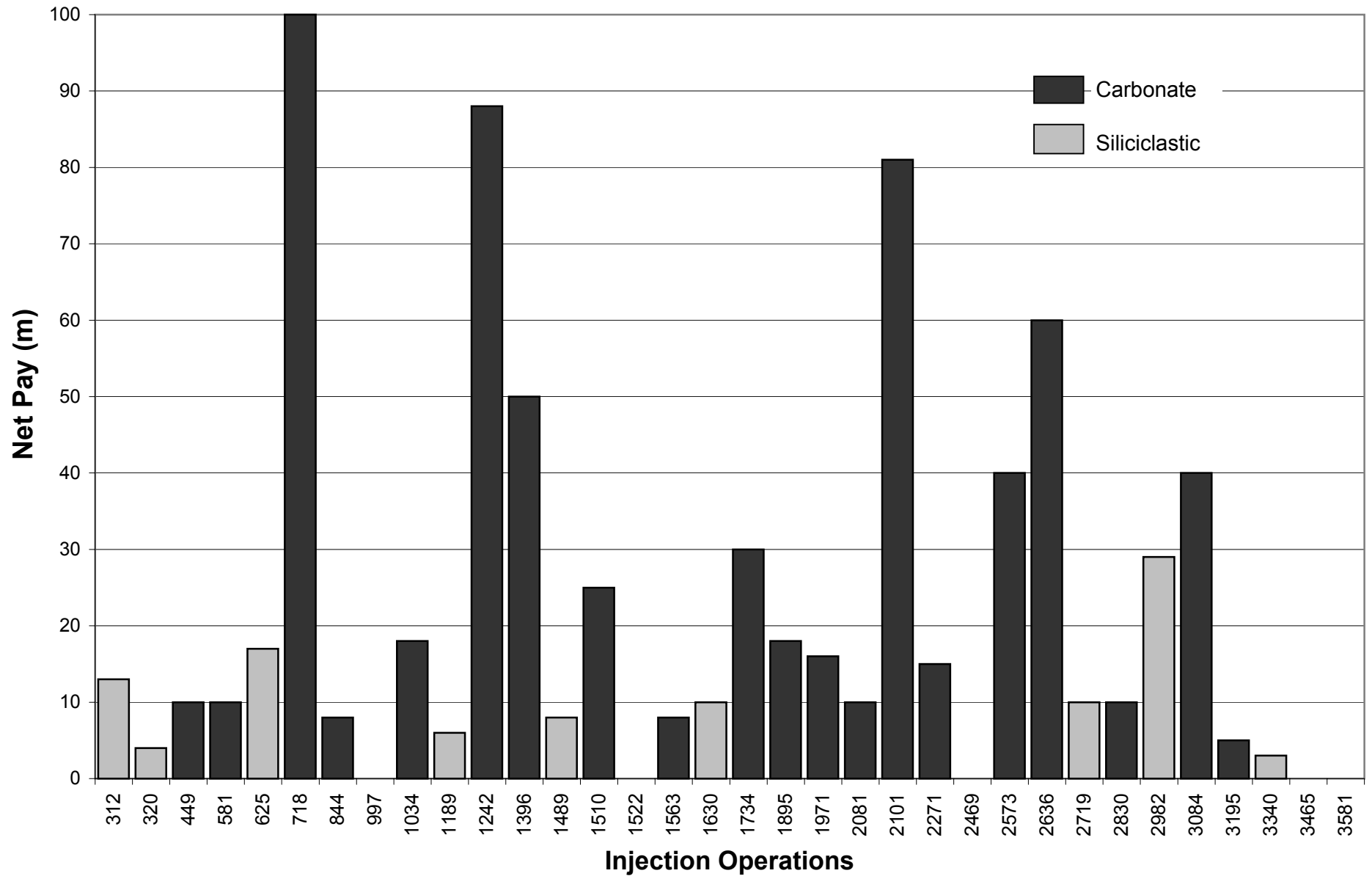
Injection Zone Depths for Alberta Acid Gas Injection Operations



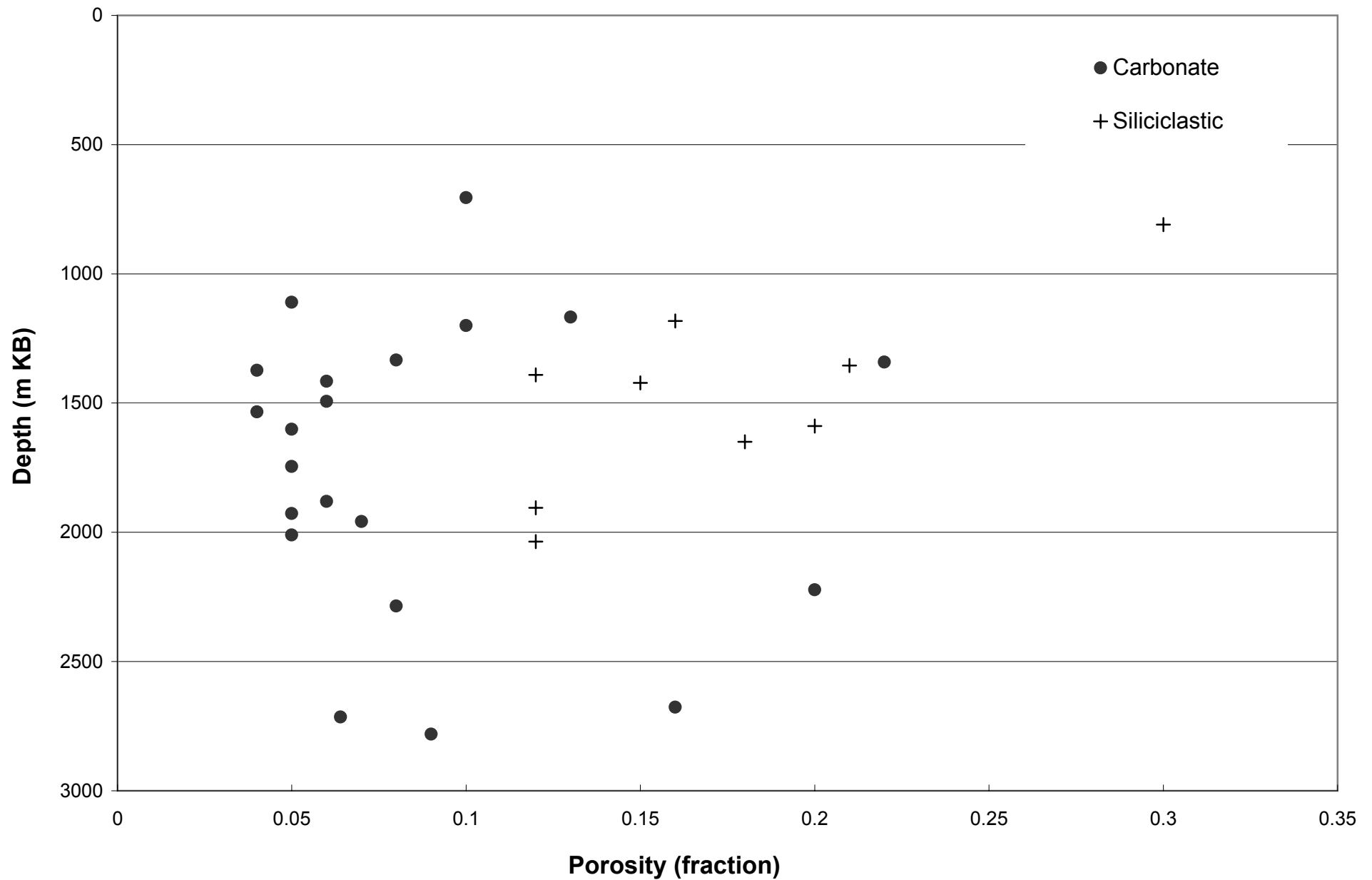
Reservoir Type and Lithology for Acid Gas Injection Operations in Alberta



Net Pay of Injection Reservoir or Aquifer



Porosity of Alberta Acid Gas Injection Zones



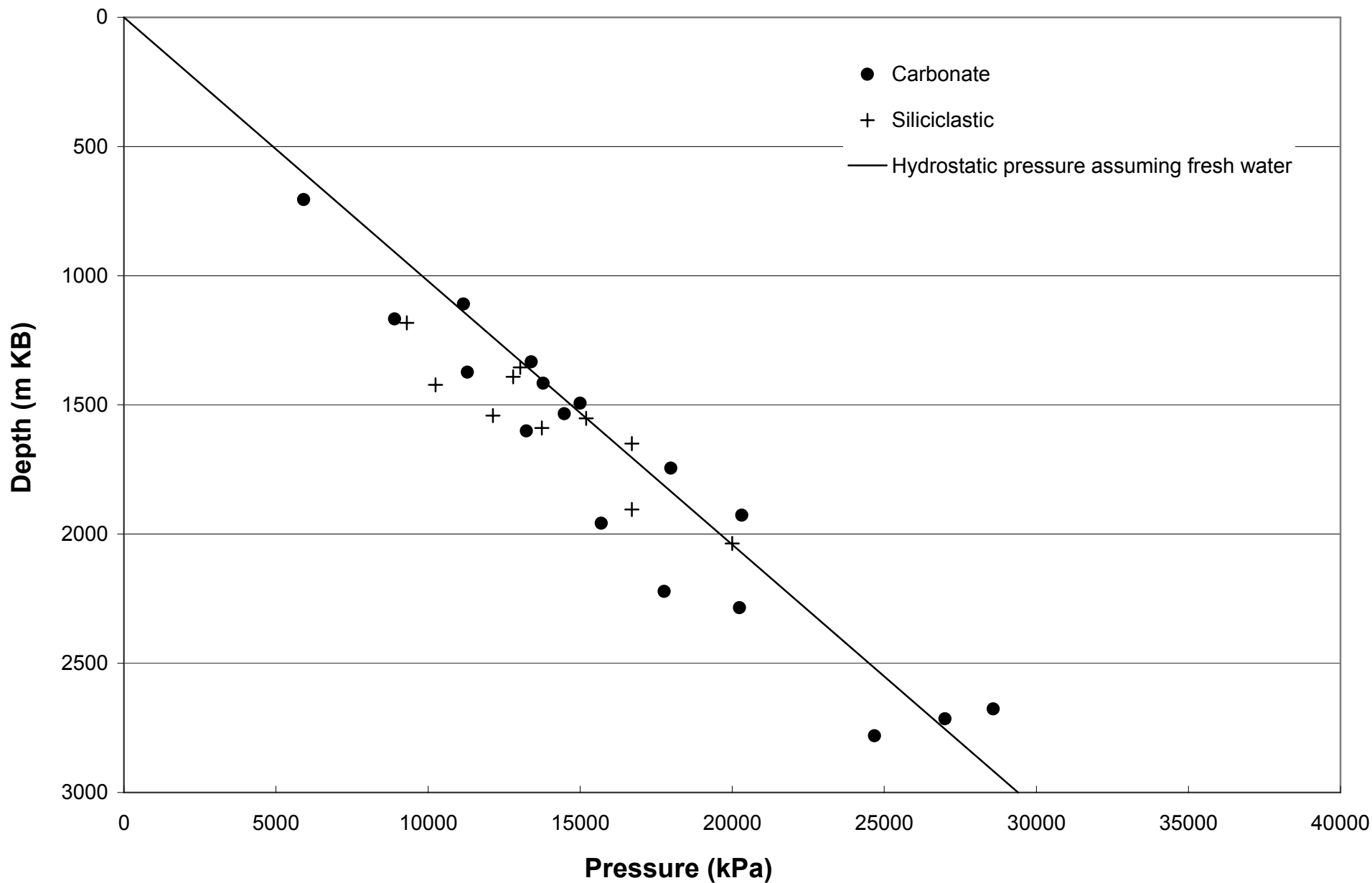
Appendix

Acid Gas Injection Operations in Alberta, Canada

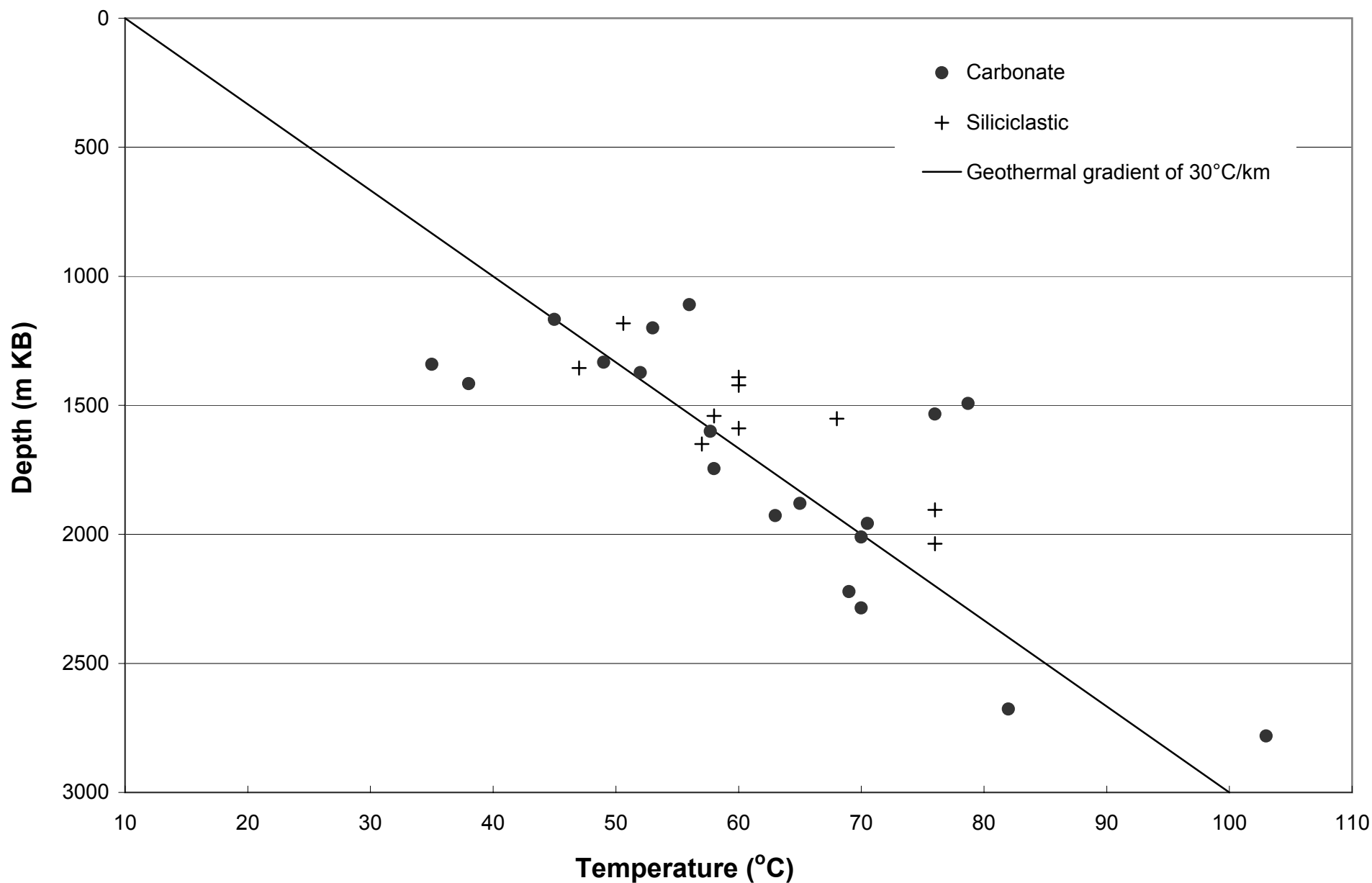
Host Fluids Graphs

- ♦ Original Formation Pressure at Injection Zones
- ♦ Formation Temperature of Injection Zones
- ♦ Formation Water Salinity
- ♦ Oil API Gravity in Depleted Oil Reservoirs used for Injection
- ♦ Specific Gravity in Depleted Gas Reservoir used for Injection

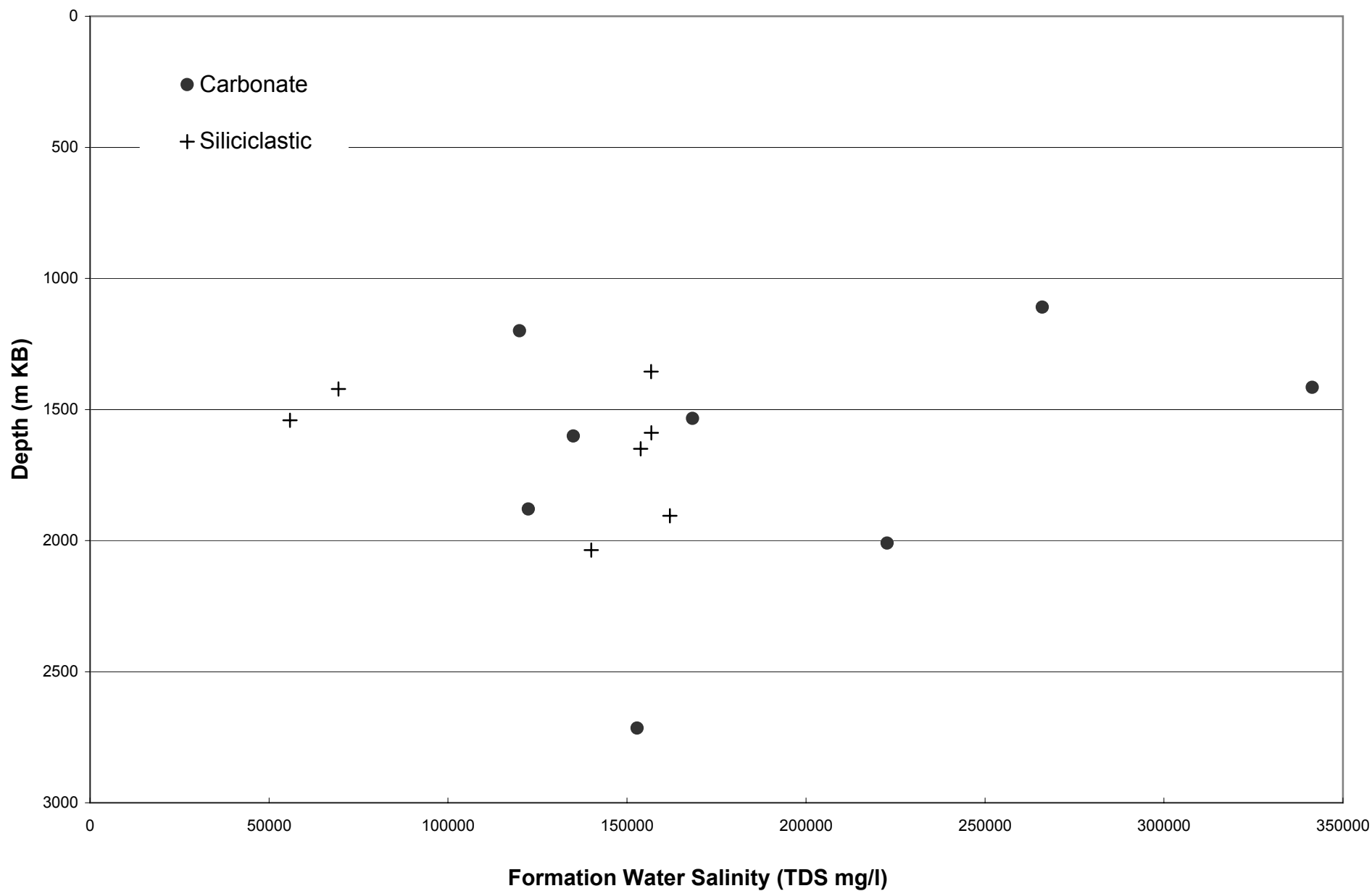
Original Formation Pressure at Alberta Acid Gas Injection Zones



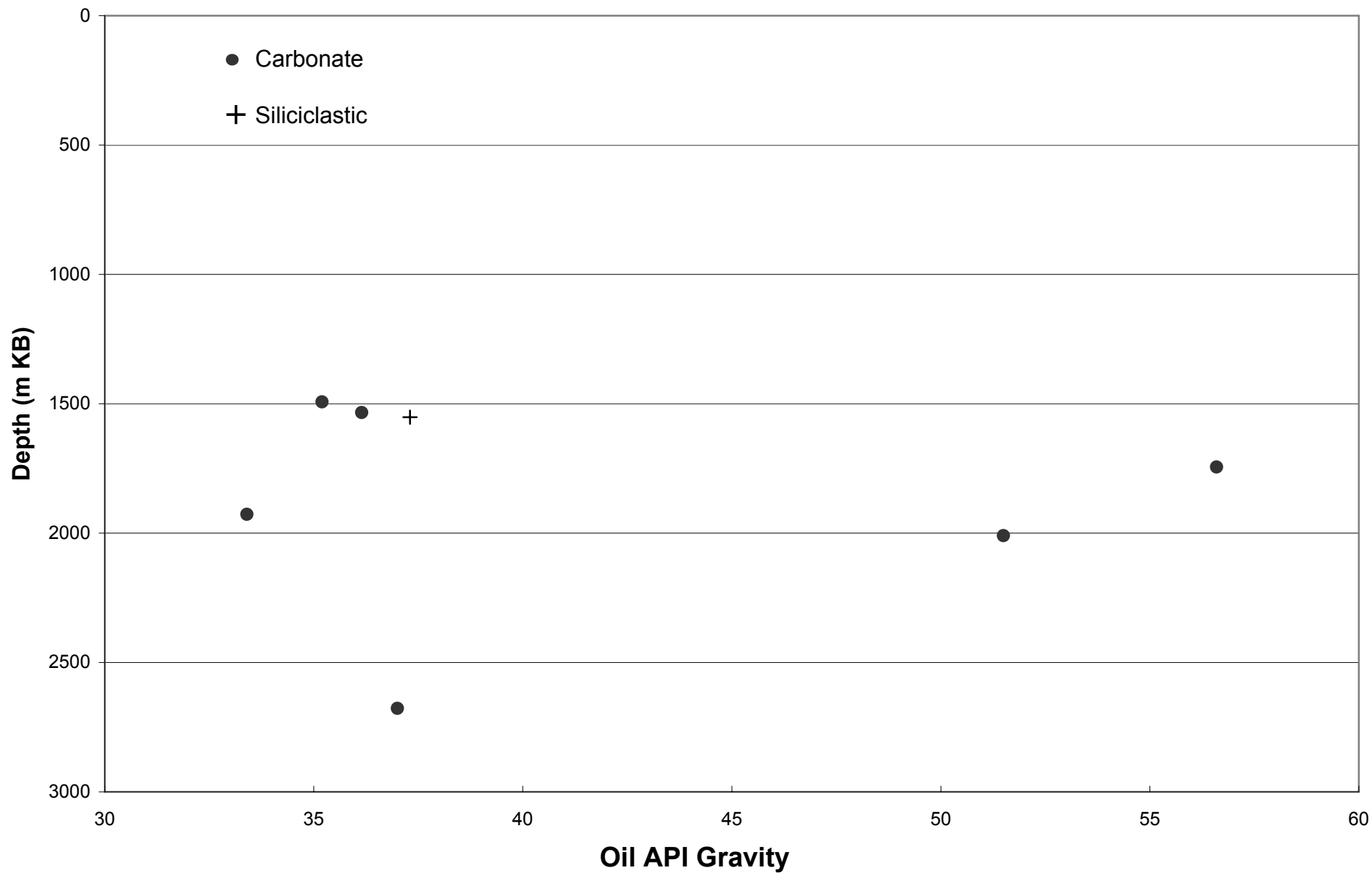
Formation Temperature of Alberta Acid Gas Injection Zones



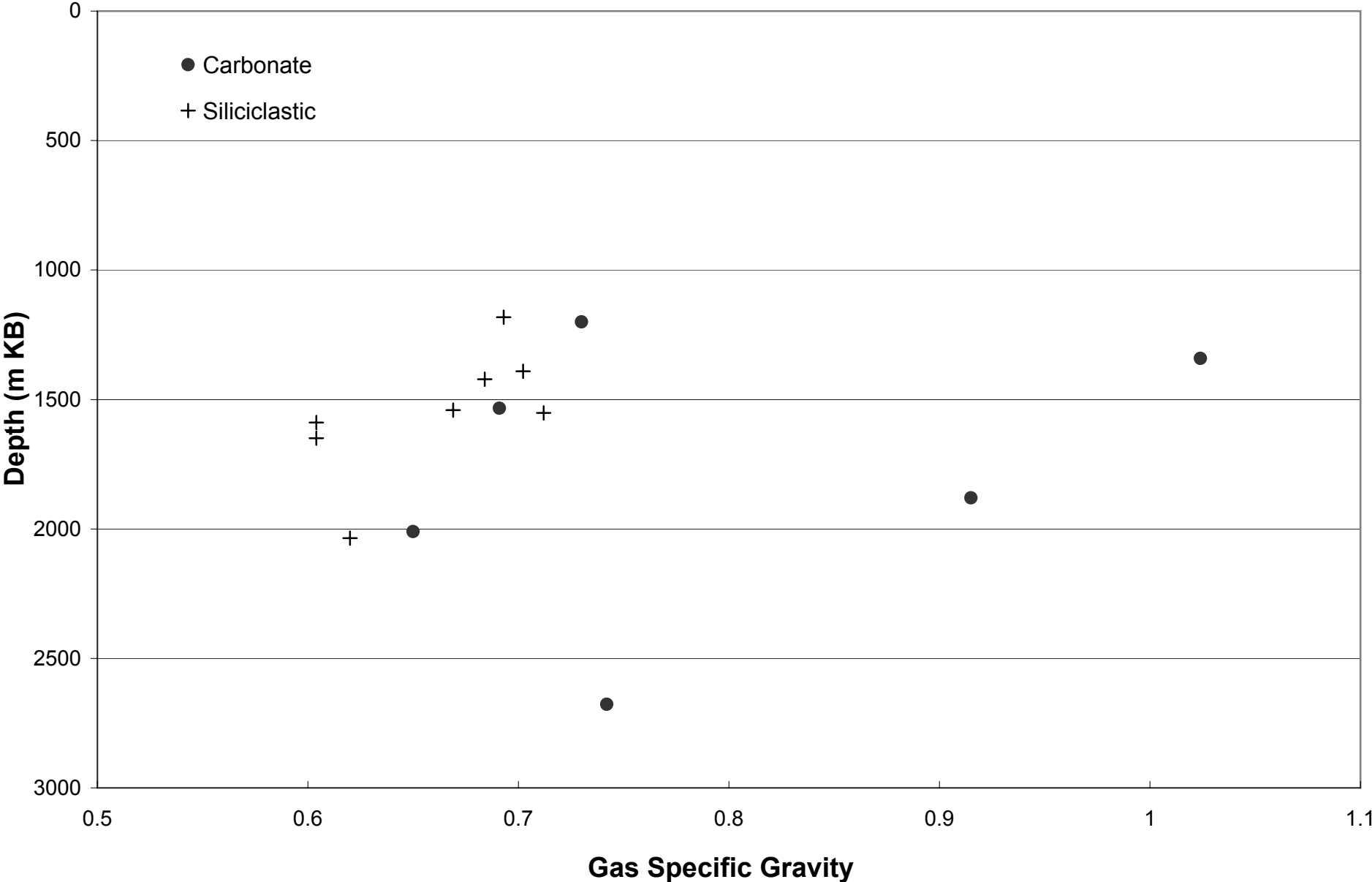
Formation Water Salinity in Acid-Gas Injection Zones of the Alberta Basin



Oil API Gravity for Alberta Acid Gas Injection in Depleted Oil Reservoirs



Specific Gravity of Natural Gas in Depleted Gas Reservoirs used for Acid Gas Injection



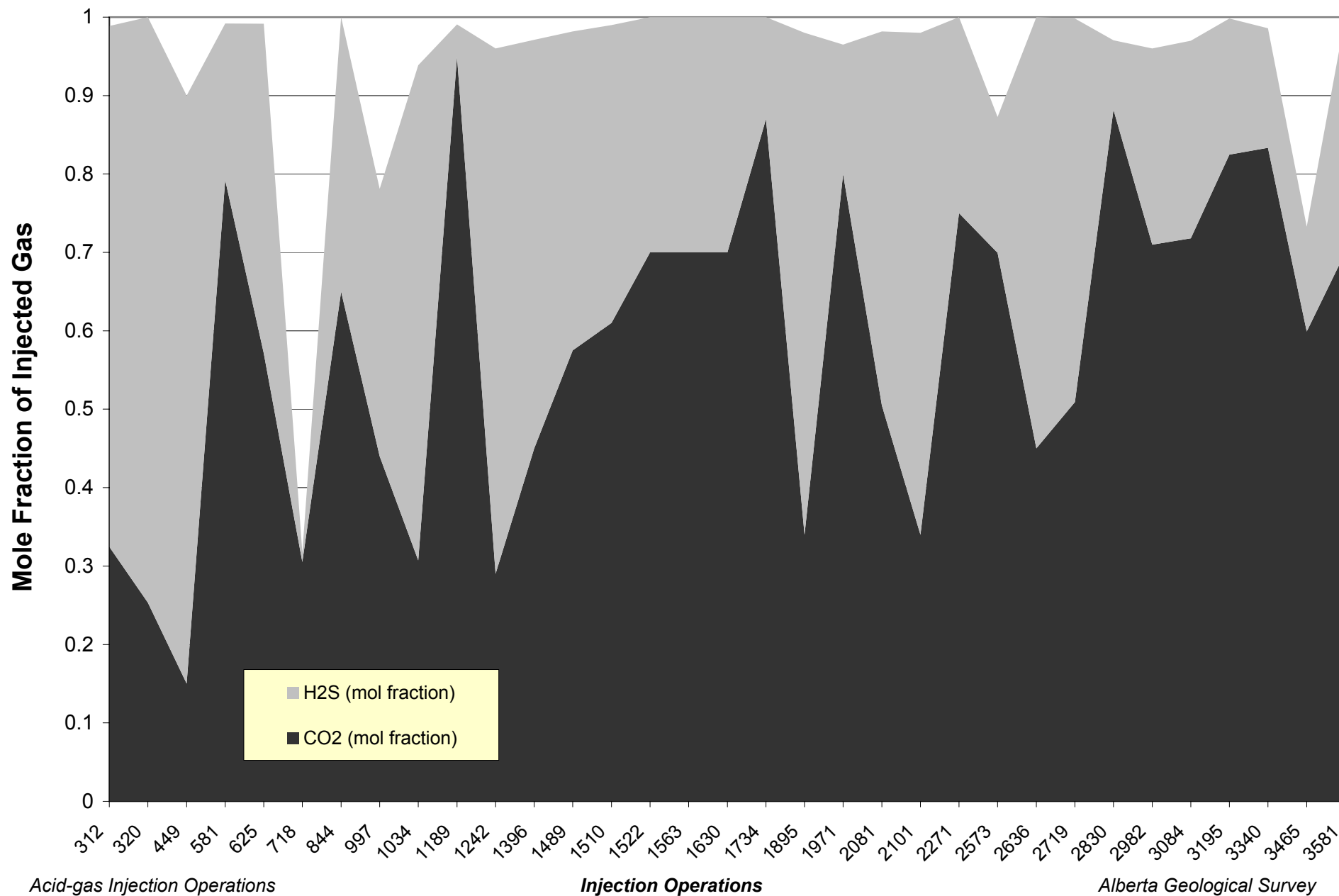
Appendix

Acid Gas Injection Operations in Alberta, Canada

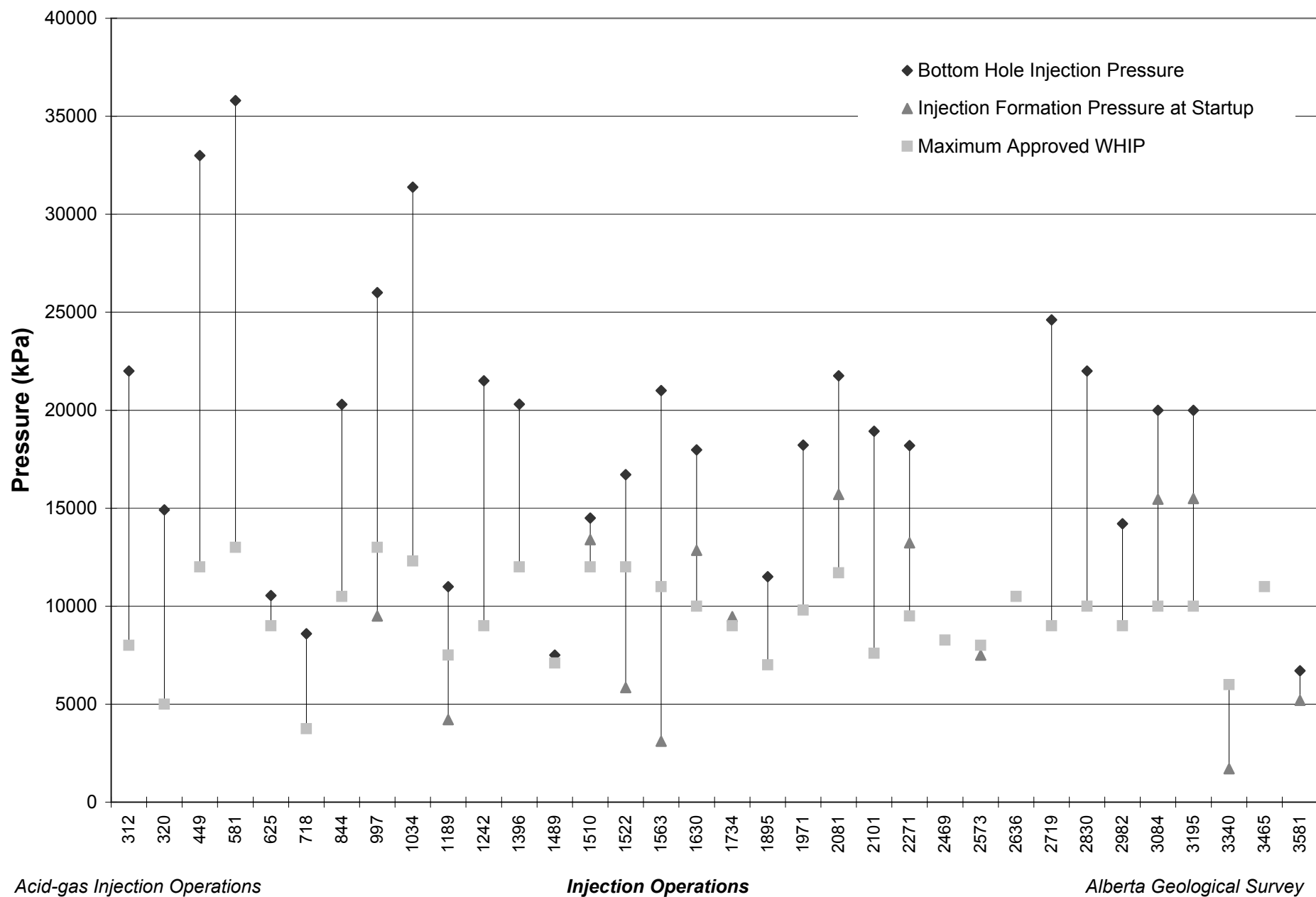
Injection Operations Graphs

- ♦ Composition of Injected Acid Gas in Alberta
- ♦ Wellhead and Formation Pressures of Acid Gas Injection Operations
- ♦ Maximum Approved Acid Gas Injection Rate
- ♦ Pipeline Length

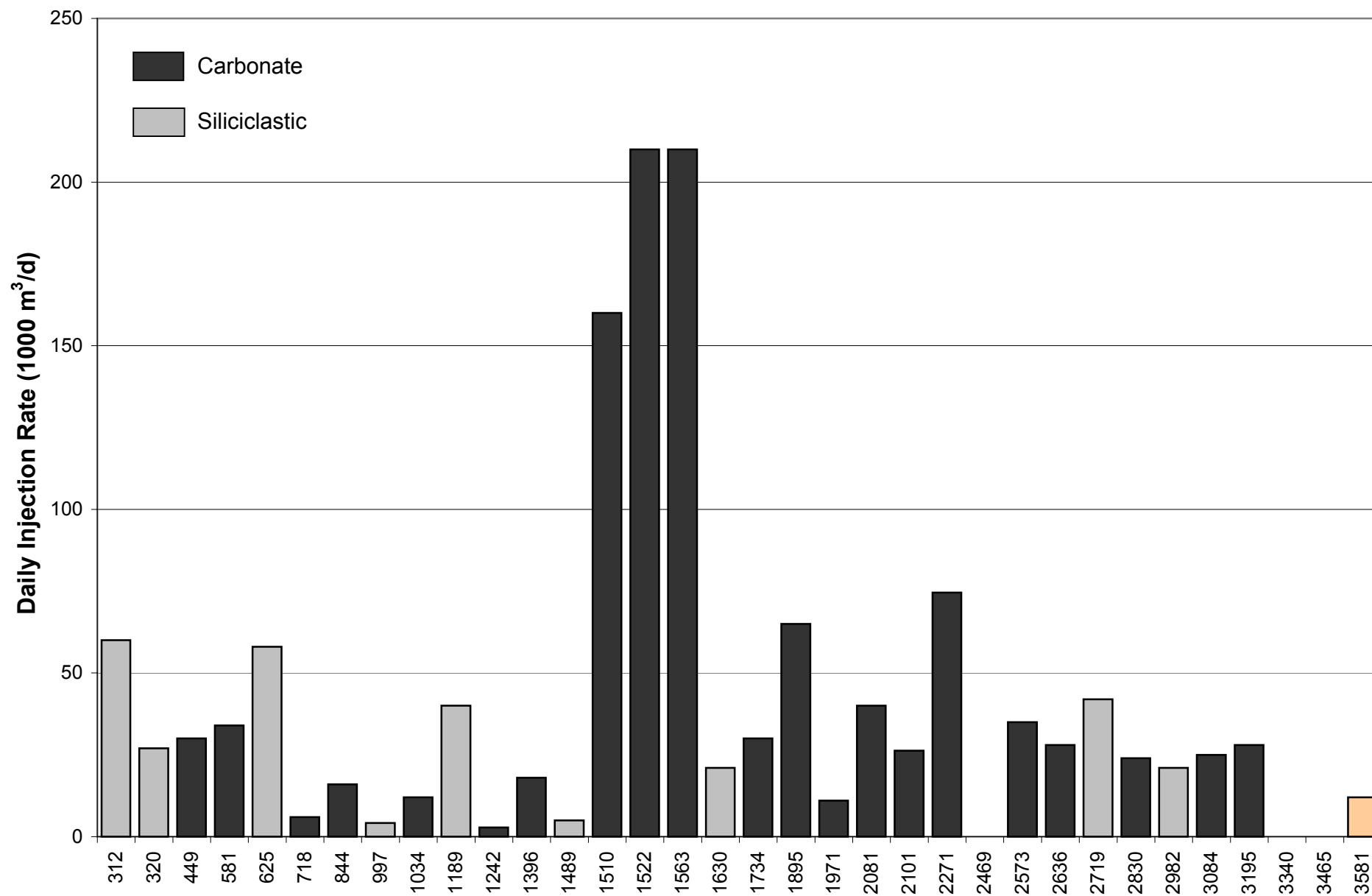
Composition of Injected Acid Gas in Alberta, as Requested in Original Applications



Pressures Associated with Acid Gas Injection Operations in Alberta



Maximum Approved Daily Acid Gas Injection Rate for Injection Operations in Alberta



Acid-gas Injection Operations

Injection Operations

Alberta Geological Survey

Pipeline Length from the Gas Plant to the Acid Gas Injection Well

