BARRIERS TO OVERCOME IN IMPLEMENTATION OF CO2 CAPTURE AND STORAGE (1) STORAGE IN DISUSED OIL AND GAS FIELDS

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Title: **Barriers to overcome in implementation of CO_2 capture and storage (1) - Storage in disused oil and gas fields**
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Other remarks:

Background to the Study

The IEA Greenhouse Gas R&D programme (IEA GHG) is systematically evaluating the cost and potential of measures for reducing emissions of greenhouse gases arising from anthropogenic activities, especially use of carbon dioxide capture and storage.

Storage of CO_2 underground is now being undertaken at commercial scale in one deep saline reservoir (aquifer). CO_2 storage in depleted hydrocarbon reservoirs should have a number of advantages over CO_2 storage in aquifers including:

- Exploration costs would be small;
- These reservoirs are proven traps, capable of holding liquids or gases for thousands to millions of years;
- They have well known properties;
- There is potential to re-use some parts of the hydrocarbon production system to transport and inject the CO_2.

A study carried out by the IEA GHG Programme in 1993[1] estimated the global capacity for CO_2 storage in disused hydrocarbon reservoirs to be about 670 Gt CO_2 (assuming the volume of recovered hydrocarbons could be replaced by carbon dioxide). It is also possible to consider storing CO_2 in partially depleted oil reservoirs as part of the process of enhancing oil recovery by CO_2-flooding of the reservoir. Enhanced oil recovery using CO_2 is currently practiced in a number of fields around the world (although mostly with natural rather than anthropogenic CO_2). None of these EOR projects has been established in order to sequester CO_2. Moreover, as far as is known, there are no proposals at present for storing CO_2 in disused oil or gas fields. The purpose of this study was to find out what are the barriers to using depleted or disused oil or gas reservoirs for storage of CO_2.

Advanced Resources International of the USA, together with Dr J Taber, carried out the study.

Industry overview

Following more than a century of intensive petroleum exploitation, particularly in Europe and North America, thousands of oil and gas fields are approaching the end of their economically productive life. These depleted fields could act as effective storage sites for anthropogenic CO_2 that would otherwise be emitted to the atmosphere.

[1] "Disposal of Carbon Dioxide Arising from Fossil-fuel Based Power Generation in Exhausted Oil and Gas Wells", Report No. IEA/93/OE15, November 1993, Contractor TNO.

In most oil fields, only a proportion of the original oil in place (OOIP) is recovered using standard petroleum extraction methods. Carbon dioxide injected into suitable, depleted oil reservoirs can enhance oil recovery (CO_2-EOR). Additional oil recovery of 10-15% of OOIP is typical with this technique. The life span of a typical CO_2-EOR project is in the range of 5 to 30 years.

Depleted natural gas fields may also be technically feasible sites for CO_2 storage. Underground storage (UGS) has been an integral part of natural gas production, transportation, and distribution systems for many decades, particularly in North America, Europe, and Australia. Natural gas is routinely injected, stored, and withdrawn from hundreds of UGS fields. It is considered that some depleted gas fields could be adapted readily for storage of CO_2. The technologies for monitoring injected gas within depleted natural gas fields are relatively mature and could be adapted to monitor and verify CO_2 storage in these settings.

Results and Discussion

The following areas are described in the report

- CO_2-EOR industry worldwide
- UGS worldwide.
- Case studies of CO_2-EOR and UGS projects.
- CO_2 storage potential for disused oil and gas storage fields worldwide.
- Economics of CO_2 storage.
- Barriers to implementation.

CO_2-EOR industry

Commercial CO_2-EOR operations are at present underway in 4 countries: the USA, Turkey, Trinidad and Canada. In addition, several small projects were undertaken in Hungary in the mid 1980's but ceased operation by the mid 1990's. These projects account for only a small fraction (0.3%) of the worldwide crude oil production. The USA accounts for the majority of CO_2-EOR oil production, with 74 current projects. Most of the projects in the USA use naturally occurring CO_2 because of its high purity and low supply costs. There are currently 4 active projects in the USA that use anthropogenic CO_2, taken from gas processing and fertiliser plants. EOR operators in the USA are currently injecting an estimated 3 million tonnes of anthropogenic CO_2 annually at net profit, and approximately 10 times that amount of naturally occurring CO_2.

One new project that will substantially extend the use of anthropogenic CO_2 is the Weyburn CO_2-EOR project due to commence operation in October 2000. This project was the subject of a recent workshop in Canada, which IEA GHG co-sponsored, (see IEA GHG Report PH3/20). A new pipeline has now been built from the Dakota Gasification Plant in North Dakota, which will transport 2.8 million m^3/day of CO_2. Spare pipeline capacity will be available for other fields in Montana, the Dakotas and Saskatchewan. Another CO_2-EOR project, which is considering sequestration of CO_2, has been proposed by BP-Amoco for an oil field on the North Slope of Alaska.

Underground gas storage

In 1998 worldwide there were over 500 UGS fields in operation representing a total gas storage capacity of some 164 000 million m^3. The United States and Canada account for about two-thirds of the worldwide UGS capacity and Europe the remainder. New UGS facilities are being considered in China and South America, as well as in the more mature North American and European systems. Most of these underground gas storage facilities are based on use of depleted oil or natural gas fields.

Reservoir matrices are typically sandstone or carbonate. In some cases, salt caverns and aquifers have also been used for UGS, but these are less common.

Case studies of CO_2-EOR and UGS projects

Six detailed case studies of CO_2-EOR projects in the USA, Canada, Turkey and Hungary are presented and reviewed. One case study is presented of a natural gas storage facility in the USA. All the case studies are for currently operating projects, with the exception of the Hungarian case, which had ceased operation by 1993. These case studies were used to develop an understanding of the feasibility and operational challenges of CO_2 storage in such reservoirs (full details are given in Section 3 of the report).

The case study of the Rangely Weber project illustrates the storage potential of a CO_2-EOR operation. It is estimated that, ultimately, quantities of CO_2 used will be 0.07 Gt CO_2 injected, 0.03 Gt CO_2 separated from the produced oil and reinjected, and 0.03 Gt CO_2 dissolved in immobile oil. About 10% of the injected CO_2 is thought to be lost, as fugitive emissions from the field, or vented from production wells. These figures show that, over its lifetime, one of the world's largest CO_2-EOR projects will in itself only have a very limited impact on worldwide CO_2 emissions. Hundreds of CO_2-EOR projects will be needed worldwide to significantly reduce CO_2 emissions to the atmosphere from anthropogenic sources.

The CO_2 storage potential in disused oil and gas fields worldwide.

A database of 155 geological provinces was used to evaluate the worldwide storage potential in disused oil and natural gas fields. This has indicated that (during the next several centuries) up to 923 Gt CO_2 could be injected and stored in these reservoirs using current petroleum technology. This storage capacity equates to over 40 years of current CO_2 emissions from all uses of fossil fuels worldwide. Of the total, storage of CO_2 in depleted gas fields would hold 797 Gt CO_2. Storage in depleted oil fields contributes a further 126 Gt of potential CO_2 storage capacity.

The economics of CO_2 storage in EOR projects.

Assuming that CO_2 is supplied at high purity and pressure, EOR projects in oil fields could sequester 120 Gt of CO_2 at net saving (see Figure 1 below). This economic estimate has assumed an oil price of $15/bbl[2]. It is noted that the oil price has a significant impact on EOR profitability. Higher oil prices would significantly reduce the net cost of storage. It should be noted that, as with other IEA GHG studies of storage options, the cost of CO_2 capture, pressurisation and transmission are not included here[3].

[2] A $15/bbl (barrel) oil price was assumed less 20% for government taxes giving a typical net wellhead price of $12/bbl worldwide.

[3] Typical cost of capture, pressurisation and transport (up to 1000 km) from a gas-fired power plant is around 45$/t$CO_2$, so the overall cost of CO_2 sequestration in this way is 10 – 62 $/t CO_2.for depleted oil fields and 52 - 62 $/t for depleted gas fields.

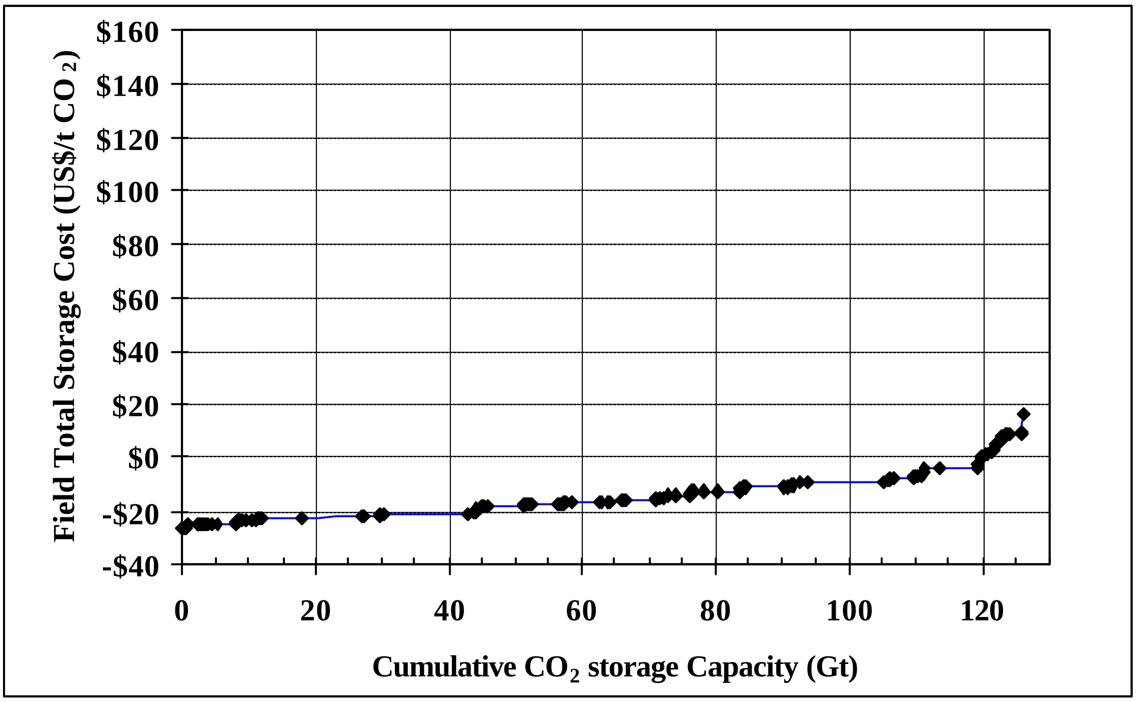

Figure 1 CO_2 storage cost curve for depleted oil fields and CO_2-EOR projects in oil fields

The costs for storing CO_2 in disused gas fields are shown in Figure 2 overleaf. Unlike the CO_2-EOR case there are no compensating benefits from storage in disused gas fields. Some 105 Gt CO_2 can be stored at a net cost of $7/t, with a further 575 Gt at a cost of $10-17/t.

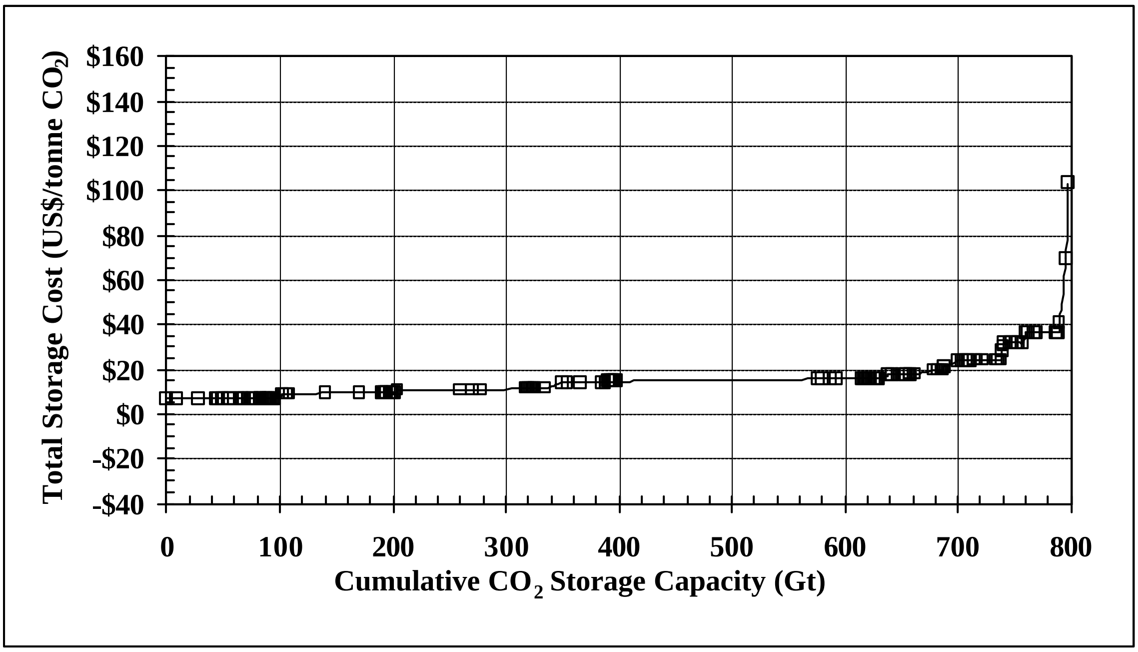

Figure 2 CO_2 storage cost curve for depleted gas fields

Comparison with previous IEA GHG study

The estimated storage potential determined in this study is higher than the previous study by IEA GHG (Report No.IEA/93/OE15), which estimated a total storage capacity of 670 Gt CO_2. In this earlier study the storage capacity in disused gas fields was estimated to be 520 Gt CO_2 and in disused oil fields 148 Gt CO_2.

For gas fields, the latest study assumes the void space left after the extraction of the hydrocarbons is filled with CO_2. The study considered that only 75% of the void space could be replaced with CO_2. The remaining 25%, was not useable due to reasons such as field edge effects and water inclusion amongst others. The methodology for estimating the storage capacity in disused gas fields for the two studies is similar (80% depletion of gas fields was assumed in the first study) and, therefore, the results are directly comparable. The increased estimate for the storage capacity in depleted gas fields in the latest study is due to a number of contributing factors including: the use of actual gas compressibility values for fields rather than assumed fixed values, and the use of new resource estimates produced by the USGS[4]. The latest USGS estimates have used probabilistic analysis to forecast future (as yet undiscovered) worldwide oil and gas fields.

For oil fields, the latest study assumed that all oil fields would be exploited by a combination of natural drive and water flood/gas injection followed, finally, by CO_2-EOR. CO_2-EOR will be carried out last because of the high cost of CO_2 supply (relative to the other options). This assumption is consistent with industry practise in the USA. In this case, the CO_2 is stored through dissolution in the remaining oil (miscible flooding), in the reservoir pore space (assuming the reservoir is not pressurised by the water) and to a smaller degree by dissolution in the water in the reservoir. The exact ratios of CO_2 in the oil and pore space etc., was considered to be currently unknown. A detailed monitoring study such as that proposed at Weyburn will be required to determine the actual mode of CO_2 storage in CO_2-EOR projects. The amount of CO_2 used in CO_2-EOR operations, and hence the amount stored was calculated from the CO_2-EOR project case studies discussed in detail in the main report. The degree of CO_2 miscibility was calculated for each oil field based on the oil characteristics and CO_2 injection rates modified accordingly. It is noted that the CO_2 injection values were based on current industry practice to maximise oil production not CO_2 storage. Operation of the field to store CO_2 from the outset would potentially result in higher CO_2 injection rates and field dewatering to maximise the void space available.

In the previous study for the oil field case, it was assumed that the maximum exploitation of the oil field would be achieved by the same process (natural drive/water flood & gas injection followed finally by CO_2-EOR), as was assumed in the current study. The maximum exploitation was assumed to be 50% of the original oil in place. The CO_2 could then be stored by filling the remaining void space after oil extraction in the reservoir was complete. The earlier study did not assume any CO_2 was stored in the remaining oil (only that the CO_2 caused the oil to swell reducing the pore space in the reservoir). The study did consider that water flooding could reduce the available storage space. The data was presented as a maximum storage potential (142 Gt CO_2) which assumed 100% CO_2 occupancy and a minimum case (3.7 Gt CO_2) that assumed only 3% occupancy due to water pressurisation of the reservoir. These values, therefore, represent the theoretical maxima and minima, whilst the true potential (based on the widespread industry practise of water flooding in many petroleum provinces worldwide) must lie somewhere in between. The methodology used to derive the figures for oil field CO_2 storage in the 2 studies was, therefore, different and the results are not directly comparable.

On balance, it is considered that the storage potential based on current actual industry experience and operational practise of CO_2 injection is considered to be the more appropriate number for CO_2 storage in oil fields, rather than the more theoretical number derived in the first study based on the use of void space alone. If, for new oil fields, industry practise were to change and CO_2 storage were maximised, storage could take place both in the void space created by oil extraction and by dissolution in the oil. In that case, the storage potential for these fields would be higher than that estimated by both studies.

[4] United States Geological Survey

Barriers to the use of depleted oil and gas fields for CO_2 storage.

The main barriers to implementation were identified through a process of consultation with oil and gas industry personnel. Information was also received as a result of the BP Amoco/USDOE/IEA GHG workshop "CO_2 Capture and Geologic Sequestration - Progress through Partnership" held in Houston in September 1999. Ways of overcoming these barriers through future R&D activity or policy changes are considered. The main barriers identified and the recommended steps for resolving them are presented below.

Barrier 1: The high costs of capturing, processing, and transporting anthropogenic CO_2.

The high cost of anthropogenic CO_2 was considered to be the major technological impediment to storage in depleted oil and gas fields. The high cost of anthropogenic CO_2 is the key reason why most EOR operators in the USA use naturally occurring CO_2. To overcome this barrier will require a long-term R&D effort directed toward evolutionary improvements of existing methods of CO_2 capture as well as breakthrough development of technologies that can dramatically lower capture costs.

Barrier 2: Incomplete understanding of reservoir processes and storage methods

The long-term effects of CO_2 storage on the integrity of the reservoir rock and the quality (sulphur and asphaltene contents) and recoverability of reservoir oil are poorly understood. Depleted oil fields that are converted to CO_2 storage almost certainly will have large and economically significant remaining oil resources. Even though most residual oil deposits may not be economically recoverable at the time the field is converted to CO_2 storage, if oil prices were to rise in future and/or more effective enhanced oil recovery technologies were to be developed, there might be pressure to convert the field back to oil production. Therefore, it is essential to consider the effects of CO_2 storage on the value and producibility of the depleted oil resources. The most effective mechanism for addressing this barrier would be to investigate the near-term storage targets, in the USA and in the North Sea.

Barrier 3: Monitoring, verification, and environmental safety of CO_2 storage

In any underground CO_2 storage project there is a need to demonstrate that the CO_2 is effectively contained within the storage reservoir. In so doing, public and governmental confidence in the storage option can be developed. To demonstrate effective containment in reasonable timescales (up to 1000 years at least) a dedicated, and scientifically sound, monitoring programme will need to be put in place to verify storage of CO_2 within the reservoir. To address this barrier it is recommended that a programme of development work coupled with some R&D should be considered.

Barrier 4: Lack of functioning emission trading system and storage regulations

The key regulatory barrier to expanding CO_2 storage in depleted oil and gas fields is the lack of a system (e.g. of taxes or credits) that can provide financial benefits to the operator of a CO_2 storage project. Currently, Norway is the only country taxing CO_2 emission, which allows operators to avoid taxes by storing CO_2. A number of experimental tradable credit systems are currently under development, although none are in routine commercial operation. Joint industry/government development of effective regulations and trading systems for storage is recommended.

Barrier 5: Conflicts between CO_2 storage and EOR or natural gas recovery

One of most serious potential barriers to CO_2 storage in depleted oil and natural gas fields may be commercial or organisational conflicts between petroleum recovery and CO_2 sequestration. The overall objectives and daily field operational procedures can differ significantly for these two activities. There is no precedent for simultaneous operation of oil and gas production with intentional storage of CO_2, particularly where storage is a wholly separate commercial enterprise.

Transferring ownership from the petroleum rights holder of a depleted oil or natural gas field to a separate sequestration rights holder is another untested and, undoubtedly, complex procedure. Depleted oil and natural gas fields always leave behind some amount of residual petroleum within the reservoir. New technologies or changes in price/cost relationships can turn an abandoned depleted field into a valuable asset once again. But converting a depleted field into a storage site may be irreversible, at least if storage is intended to be permanent and credits meaningful and verifiable.

Natural Gas Storage Conflicts*:* Depleted gas production fields located close to demand centres often live a second life of natural gas storage operations. Gas storage fields are used to smooth out seasonal supply and demand variability, buying and injecting natural gas during low-demand periods (typically summer) and withdrawing supplies during high demand (winter). Given their close proximity to gas demand (and therefore inevitably CO_2 emissions) centres, these are indeed the very fields that would be in demand for storage.

Using depleted gas fields for gas storage will compete with CO_2 storage and, depending on the value of emissions credits, may even be a higher-value commercial activity. But once CO_2 injection into a depleted gas field begins, the residual gas resource will rapidly be contaminated, destroying any residual gas storage value. One potential transfer method may be to allow the current gas production/storage rights holder to auction off the field to the highest bidder, whether for production, storage, or sequestration uses. In this way (barring information barriers), the market system should be able to accurately set alternative values, and price the sequestration rights accordingly.

EOR Conflicts: The potential conflicts with depleted oil fields are more subtle and possibly even more complex than in depleted gas fields. In a routine EOR project, the operator seeks to minimise CO_2 injection and sequestration, while maximising oil recovery. This is because CO_2 is a costly commodity and the largest single operating expense. But from a storage point of view, more credits obviously will be earned by maximising sequestration.

The most efficient solution to solve this dilemma may be to assign any storage rights to the current petroleum production rights holder. In this way, the field operator could maximise their total return on investment for both EOR and storage activities. This would also enable the field operator to respond rationally to changes in oil prices, technology, costs, and the market value of traded sequestration credits. Ownership of both rights would also reduce conflicts between separate petroleum rights and sequestration rights holders. For inactive fields the government could auction recovery and storage rights.

To overcome these barriers, it is recommended that a detailed engineering analysis of a specific depleted oil field be undertaken to characterise and assess potential conflicts between CO_2-EOR and CO_2 storage. This exercise would best be performed at a new, greenfield EOR project, such as at PanCanadian's Weyburn EOR flood in Saskatchewan, Canada or BP Amoco's planned EOR project on the North Slope of Alaska, U.S.A. Issues that require assessment include:

- ***EOR vs. Sequestration.*** Economic evaluation of optimal CO_2/oil ratio, given likely future oil prices and values for CO_2 storage credits.
- ***Greenfield vs. Depleted Fields.*** Injected water needs to be minimised, because water and CO_2 compete for space in the reservoir. Injecting CO_2 during the early stages of reservoir exploitation

could improve oil recovery while simultaneously maximising CO_2 storage. This concept requires detailed evaluation.

- ***Gas Recovery vs. Sequestration:*** The use of CO_2 to maintain reservoir pressure or as base gas for underground gas storage in depleted gas fields has been proposed and also requires evaluation.

Expert Group Comments

Two sets of expert reviewers assisted in the review of this study. The first group comprised reviewers selected by the Programme and a number recommended by the Programme's members. In addition, a second group of reviewers drawn from the oil and gas industry were asked to assess the study report findings, as it was considered important to have a strong oil and gas industry input to the review.

The comments drawn from both expert groups were generally complimentary of the study. Many of the comments received were editorial. In addition, a number of the oil and gas industry experts identified some errors in the data presented relating to field operational characteristics and production statistics from their respective fields. All these points have now been corrected.

A significant criticism of the draft report was that it focused too heavily on CO_2-EOR. To address this point the report was modified by the contractor to include more detail on gas field storage potential, inclusion of a disused gas field in the industry case studies and information on the worldwide use of gas storage. In addition, the barriers discussion was extended to include a discussion on future R&D and policy actions to overcome them.

Major Conclusions

The study has identified that the storage of CO_2 in depleted oil and gas reservoirs has significant potential (923 Gt). The more significant storage option is depleted gas fields (797 Gt) compared to 129Gt in CO_2-EOR operations in oil fields. However, it is more expensive to store CO_2 in depleted gas fields because unlike CO_2-EOR there are no benefits in terms of increased revenues from oil production. In oil fields, 120 Gt of CO_2 can be stored at no net cost. In depleted oil and gas fields some 105 Gt of CO_2 can be stored at a net cost of $25/t, with a further 195Gt at a cost of $30/t and finally further a 350Gt at a cost of $35/t. In total some 700 Gt CO_2 can be stored at costs below $40/t.

The study identified that, despite the potential for CO_2 storage in disused oil fields, there were a number of barriers that were restricting the implementation of this storage option. One of the most significant barriers is economic, which is the high cost of capture, processing and transportation of anthropogenic CO_2. It is the high cost of anthropogenic CO_2 that has forced most operators in the USA to use natural CO_2 supplies. Technical/environmental barriers include the current incomplete understanding of reservoir processes and storage methods and the issue of the environmental safety of CO_2 storage. The lack of a functioning emission trading system and storage credits was seen as a significant regulatory barrier. On the commercial side the transference of ownership of a depleted field from the licensed operator to a storage operator is an untried and undoubtedly complex procedure. One other point to note is that although the fields have limited economic value when abandoned they will still contain oil and gas resources. In the future new recovery techniques might allow these fields to become economically viable again; assuming the storage of CO_2 has not contaminated the oil or gas.

Recommendations

The contractor made a number of recommendations for future study, which are discussed in detail in the main report. In the overview of the study IEA GHG has concentrated on the recommendations made by the contractor concerning ways of overcoming the barriers identified which was the main focus of the study.

The study has recommended that investigations of how to overcome the economic, technical and environmental barriers to use of depleted fields would be best done as a joint industry/government R&D programme. Details of the scope of this R&D programme are given in the main report.

This study also emphasises the need for an R&D programme to assess both near and long term options to reduce anthropogenic CO_2 capture and processing costs, as has been recognised in other IEA GHG studies.

To address the regulatory barriers a joint industry/government workshop or action group is recommended to consider emissions trading and tax credits for the oil and gas industry.

In the case of the commercial barriers it is recommended that a detailed engineering analysis of a specific oil or gas field be undertaken to assess the potential conflicts that might arise between CO_2-EOR and CO_2 storage. A new greenfield site should be used for this engineering analysis. In the EOR case the proposed CO_2-EOR projects at Weyburn or the BP Amoco project on the Alaskan North Slope would be good candidates.

Sequestration of CO_2 in Depleted Oil and Gas Fields:

Barriers to Overcome in Implementation of CO_2 Capture and Storage (Disused Oil and Gas Fields)

IEA/CON/98/31

Final Report (Revised)

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Commonly Used Abbreviations

EOR	Enhanced oil recovery
CO_2-EOR	Enhanced oil recovery using CO_2 injection
BO	Barrel of oil
MBO	Thousand barrels of oil
MMBO	Million barrels of oil
BBO	Billion barrels of oil (10^9)
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet (10^9)
Tcf	Trillion cubic feet (10^{12})
$/Mcf	U.S. dollars per thousand cubic feet
$/t	U.S. dollars per metric tonne
$/BO	U.S. dollars per barrel of oil
BOPD	Barrels of oil per day
BWPD	Barrels of water per day
Mcfd	Thousand cubic feet per day
MMcfd	Million cubic feet per day
Bcfd	Billion cubic feet per day
OOIP	Original oil in place
OGIP	Original gas in place
t	Metric tonne
Gt	Gigatonne
m^3	Cubic meters
m^3/day	Cubic meters per day

Executive Summary

During the next several centuries, up to 923 Gt of carbon dioxide could be injected and sequestered within depleted oil and gas fields worldwide using current petroleum technology. This storage capacity equates to about 125 years of current worldwide CO_2 emissions from fossil-fuel fired power plants. Off-the-shelf and near-term technologies developed by the commercial enhanced oil recovery (EOR) and underground gas storage (UGS) industries provide a firm basis for assessing the potential for CO_2 sequestration in depleted oil and gas fields.

Assuming that CO_2 is supplied at high purity and pressure ("Free CO_2"), EOR projects in depleted oil fields could sequester 120 Gt of CO_2 at net profit to the oil field operator (**Table 1**). Another 746 Gt could be sequestered in depleted oil and natural gas fields at relatively low costs of less than US$30/t of CO_2. Full-cycle sequestration costs would be higher if gas processing plant or power plant flue gas CO_2 sources were used. Incentives of $30 to $80/t would be needed to encourage sequestration of power plant CO_2 in depleted oil and gas fields. New technologies that reduce CO_2 costs or improve EOR or CO_2 injection efficiency could lower sequestration costs.

This study was commissioned by the IEA Greenhouse Gas R&D Programme, with additional support from the U.S. Department of Energy for analysis of depleted oil and gas fields in the United States. The U.S. potential for CO_2 sequestration in depleted oil and gas fields totals an estimated 98 Gt (1,853 Tcf). Although the U.S. accounts for only about 10% of the global sequestration potential, 93% of current worldwide CO_2-EOR production takes place there, along with two-thirds of global underground gas storage. EOR operators in the U.S. are currently storing an estimated 3 million tonnes (55 Bcf) of anthropogenic CO_2 annually at net profit, and approximately 10 times that amount of naturally occurring CO_2 -- with no emissions credits. The technical and economic assumptions for this study drew heavily on the performance of EOR and UGS projects in the U.S.

A data base and economic model of CO_2 sequestration in depleted oil and gas fields was constructed, comprising 155 geologic provinces that account for 90% of worldwide hydrocarbon potential. The model incorporates recent assessments by the U.S. Geological Survey on global hydrocarbon production, reserves, and resources. Capital and operating costs for CO_2 sequestration were estimated for each geologic province, based on commercial EOR and UGS projects. The supply cost of CO_2 injectant generally is the single most important cost variable. Other key economic parameters include oil prices, net CO_2 injected/EOR produced ratio, reservoir depth, surface setting (onshore vs. offshore), and distance from potential CO_2 supplies. A cost/sequestration curve, the first developed for depleted oil and gas fields, is provided in **Figure 1**.

The most attractive sequestration candidates are depleted oil fields that screen positively for miscible EOR, are at moderate depth, and are located close to low-cost anthropogenic CO_2 supplies, such as natural gas processing or fertilizer plants. In such favorable settings, sequestration of anthropogenic-sourced CO_2 may be profitable on the basis of incremental oil revenues. The best documented example, the Permian basin located in the southwestern U.S., generates net profit using anthropogenic CO_2, at oil prices greater than about $15/barrel. But most other settings are higher cost under current technology and infrastucture development, and would require financial incentives to operate. Deep, offshore depleted gas fields that are remote from anthropogenic CO_2 supply sources would be the most costly sequestration sites.

Finally, this study examines the barriers that are impeding more widespread application of CO_2 sequestration in depleted oil and gas. Petroleum operators were interviewed regarding their plans and concerns for using this technology. Under the current, short-term viewpoint of EOR, operators generally do not consider safety, security of storage, reservoir damage, or the level of current technology to be insurmountable obstacles. However, under the long-term time scale needed for sequestration, substantial (but incremental) technological improvements are needed to optimize and verify CO_2 sequestration. The barriers, and recommended steps needed for their resolution, may be grouped into five issues:

Barrier 1: High costs of capturing, processing, and transporting anthropogenic CO_2.

Recommendations: This is perhaps the major technological impediment to sequestration in depleted oil and gas fields, as well as in other settings, and requires a long-term R&D effort, both towards evolutionary improvements of existing methods and breakthrough technologies that can dramatically lower capture costs.

- ***Basic R&D:*** Conduct basic R&D on promising CO_2 capture technologies, such as amine separation, oxygen firing, pre-combustion decarbonization, and advanced methods such as electric swing adsorption, membranes, hydrates, cryogenic condensation, hybrid systems.

- ***Applied R&D:*** Joint industry/government funded programs to field test CO_2 capture and processing technologies in depleted oil and gas field applications.

- ***CO_2 GIS Data Base:*** Map anthropogenic CO_2 sources vis-à-vis depleted reservoirs. Develop a comprehensive GIS data base with locational information on major anthropogenic CO_2 sources, along with depleted oil and gas fields positions and storage capacities/characteristics. Such a product, made available widely and free of charge, could help industry to match CO_2 sources with sequestration opportunities.

Barrier 2: Incomplete understanding of reservoir processes and sequestration methods

Recommendations: Evolutionary R&D leveraging from off-the-shelf petroleum extraction technologies could address this barrier during the near- to medium-term (1-10 years).

- ***CO_2 – Rock/Fluid Interaction:*** Conduct research to quantify the chemical and physical reactions of injected CO_2 with rock and reservoir fluids. Test major reservoir rock types, including sandstone, siltstone, carbonate, and salt. Test long-term interactions of CO_2 with hydrocarbon and other formation fluids.

- ***Reservoir Studies:*** Assess the feasibility of CO_2 flooding in poorly characterized petroleum provinces, particularly those outside the southwestern United States. Perform detailed feasibility studies of CO_2 flooding in representative depleted oil and gas fields from the top-ranked petroleum provinces.

- ***Reservoir Models:*** Upgrade existing industry numerical simulation models to enable them to explicitly address CO_2 sequestration, both in depleted oil and gas fields. Such models will be essential for operating sequestration projects, as well as providing supporting documentation and verification for emissions trading.

- ***Natural CO_2 Fields:*** Analyze the geology and operational history of the large natural CO_2 deposits in the southwestern U.S. that have been developed for production (McElmo, Bravo and Sheep Mountain Domes). These deposits constitute a convenient laboratory for evaluating the storage, movement, and long-term integrity and chemical interaction of CO_2 within underground reservoirs.

Barrier 3: Monitoring, verification, and environmental safety of CO_2 sequestration

Recommendations: Again, evolutionary R&D building from existing petroleum extraction technology could address this barrier during the near to medium term. Educating the general public about the realistic risks of sequestration should be a continual effort.

- ***Current EOR and UGR Technologies:*** Field test and modify for sequestration the existing reservoir monitoring techniques that currently are employed by the EOR and UGR industries, such as petrophysical, geochemical, and production logging; well testing and sampling; pressure monitoring and sampling wells; and computer simulation.

- ***Advanced Methods:*** Develop medium-term monitoring technologies, such as 4-dimensional, 3-component seismic monitoring; gravity; and other geophysical and petrophysical techniques. Advanced reservoir models that more accurately reflect the interactions between injected CO_2 and reservoir fluids and strata also are needed.

- ***Natural CO_2 Fields:*** Conduct further study of the natural CO_2 fields in the western U.S. to evaluate the stability, safety and environmental impacts of long-term CO_2 storage within underground reservoirs.

Barrier 4: Lack of functioning emission trading system and sequestration regulations

Recommendations: Support joint industry/government development of effective regulations and trading systems for sequestration.

- ***Regulations:*** Industry could help shape regulation of CO_2 sequestration by first demonstrating how CO_2 and gas injection activities have been safe and effective in the EOR and UGR sectors. A workshop, modeled after the September 1999 BP Amoco Houston workshop, could be convened by industry and government participants to focus explicitly on regulation of CO_2 sequestration and monitoring issues.

- ***Emissions Trading:*** The cost/sequestration curves generated by this study provide an indication of the impact that emissions credits could have in bringing on additional, economically viable sequestration capacity. This economic evaluation, and further refinements, should be communicated to all parties active in the emissions trading debate, including officials shaping GERT, PERT, Trans Alta Corp., U.S. Senate bill S.547 and other nascent trading systems.

Barrier 5: Conflicts between CO_2 sequestration and EOR or natural gas recovery

Recommendation: These second-order technical issues could be addressed in the near to medium-term by detailed case studies of existing EOR and UGS projects, followed by field testing.

- ***EOR vs. Sequestration.*** Evaluate optimal economic CO_2/oil ratio, given likely future oil prices and values for CO_2 sequestration credits. Study selection of CO_2 injection zones, pressures, and schedules to optimize sequestration and EOR.

- ***Green Fields vs. Depleted Fields.*** Study methods for minimizing water injection, because water and CO_2 compete for space in the reservoir. Injecting CO_2 during the early stages of reservoir exploitation could improve oil recovery while simultaneously maximizing CO_2 sequestration. This concept requires detailed evaluation.

- ***Gas Recovery vs. Sequestration:*** The use of CO_2 to maintain reservoir pressure or as base gas for underground gas storage in depleted gas fields has been proposed, even though the risk of contamination of natural gas reserves is obvious. This concept also requires evaluation.

Table 1: CO_2 Sequestration Potential in Depleted Oil & Gas Fields (Gt CO_2)

Estimate (Gt CO_2)	**CO_2 Supply Costs =$0/t**	**@$0-30/t**	**@>$30/t**	**Total**
Depleted Oil Fields/ Enhanced Oil Recovery	120	6	0	126
Depleted Gas Fields	0	740	57	797
Total	**120**	**746**	**57**	**923**

Fig 1

1.0 INTRODUCTION: CO_2 SEQUESTRATION IN DEPLETED OIL & GAS FIELDS

1.1 Overview

One of the most promising technologies for sequestering anthropogenic carbon emissions is to inject and store CO_2 within depleted oil and gas fields. Following more than a century of intensive petroleum exploitation, particularly in Europe and North America, thousands of oil and gas fields are approaching or are already past their economically productive life. These fields are close to abandonment or have already been abandoned. Many of these fields could act as effective storage sites for anthropogenic CO_2, including power plant emissions and gas processing waste streams, that would otherwise be emitted to the atmosphere. In certain favorable reservoir settings, such as in certain depleted oil fields of the southwestern United States, injection and storage of CO_2 has been underway for several decades as part of profitable enhanced oil recovery operations – without emission reduction credits.

However, current understanding of the most appropriate technologies, geologic settings and regulatory structures for CO_2 sequestration in depleted oil & gas fields is still limited, particularly outside of the U.S. To realize the large potential that depleted oil and gas fields offer for sequestering CO_2, a number of technical, commercial and administrative obstacles first must be resolved. Overcoming these obstacles could enable CO_2 storage in depleted oil and gas fields to be applied on a scale large enough to achieve globally meaningful reductions in CO_2 emissions.

This study was commissioned by the IEA Greenhouse Gas R&D Programme. In addition, we have augmented the IEA effort with support from the U.S. Department of Energy for more in-depth study of sequestration in depleted oil and gas fields in the United States. Our study a) assesses the existing and emerging technologies and operational strategies for CO_2 injection into depleted oil & gas reservoirs; b) provides detailed estimates of the unit cost and sequestration capacity in more than 150 individual petroleum provinces worldwide; and c) examines the diverse technical, regulatory, environmental, and commercial barriers currently facing more widespread adoption of this promising technology.

This study considers "conventional" oil and gas reservoirs only. "Unconventional" reservoirs, including coalbed methane, tar sands (as well as non-petroleum potential CO_2 sequestration sites, such as aquifers) are outside the defined scope of work, although they also warrant continued study within the larger discipline of geological sequestration. Several of these other candidate technologies for geological sequestration have already been assessed by IEAGHG and other groups (e.g., Stevens and Spector, 1998).

We have organized the report into the following seven Sections:

1.0 - Introduction: An overview of previous research on CO_2 sequestration in depleted oil and gas fields and a general introduction to CO_2 injection technology.

2.0 - The Worldwide CO_2-EOR and Underground Gas Storage Industries: Profiles and current status of over 75 active CO_2-flood projects in depleted oil fields in the United States and other countries, and projected future activity. Overview of underground natural gas storage activity and technology.

3.0 - Case Studies of CO_2-EOR and Gas Storage Projects: Detailed analysis of six CO_2-floods in depleted oil fields and one gas storage field in the U.S. and three other countries. These case studies illustrate the range in geologic/surface settings and reservoir performance that may be expected for CO_2 sequestration projects.

4.0 – Methodology for Estimating CO_2 Sequestration in Depleted Oil & Gas Fields: A new proposed methodology for estimating actual current and potential future sequestration in enhanced oil recovery projects, non-EOR depleted oil, and depleted gas fields.

5.0 - CO_2 Sequestration in Worldwide Depleted Oil and Gas Fields: Analysis of CO_2 flooding potential of selected oil and gas fields outside the United States, based on a literature review.

6.0 – Economic Model of CO_2 Sequestration in Depleted Oil and Natural Gas Fields: Description of the economic model and data bases used for estimating the sequestration potential in global depleted oil and gas fields, including cost/sequestration supply curves.

7.0 - Barriers to Implementation: The significant technical, economic, commercial, administrative, and environmental impediments to CO_2 sequestration in depleted oil and gas fields.

Appendix 1: Detailed data base and model output, assessing the cost and sequestration capacity within depleted oil and gas field for the world's 155 largest petroleum provinces.

1.2 Advantages/Disadvantages of CO_2 Storage in Depleted Oil & Gas Fields

Geological sequestration of CO_2 may be technically feasible within a variety of reservoir settings, including disused oil and gas fields, saline aquifers, deep coal seams, and sub-seabed strata. Although each of these methods holds potential for effective sequestration under certain surface and sub-surface conditions, storage within depleted oil & gas fields holds significant comparative advantages, including:

- **Beneficial Oil Recovery.** Injection of CO_2 in depleted oil fields can enhance oil recovery, which can help offset the costs of injection. In certain favorable settings, as currently in the southwestern United States, CO_2 sequestration can actually generate significant net profits, even without the benefit of emission reduction credits. (This advantage does not apply to depleted gas fields.)

- **Proven Technology.** Commercially proven technology has been developed by the EOR and UGS industries to screen, design, operate, and monitor gas injection into depleted oil and gas fields.

These technologies could be readily adapted to the specific requirements of CO_2 sequestration. In addition, depleted oil and gas fields are much better characterized than those of commercially non-productive strata (such as saline aquifers). Extensive well and seismic data are collected during normal petroleum field exploitation, providing an invaluable source of understanding about depleted reservoirs. In contrast, deep saline aquifers, sub-sea settings, and even most coalbed methane areas tend to be poorly surveyed by well and seismic data. This increases the cost and risk of CO_2 sequestration in those settings.

- **Intrastructure.** Certain components of existing petroleum infrastructure (pipelines, wells, offshore platforms, etc.) within many disused oil and gas fields may be adapted for CO_2 storage purposes, reducing the effective capital costs of CO_2 sequestration.

- **Integrity of Storage.** Disused natural gas fields and most oil fields are proven gas traps, ensuring that injected CO_2 would be sequestered for geologic time (millions of years). Because aquifers are dynamic systems, much of the injected CO_2 would eventually escape over such a long time frame.

On the other hand, the use of depleted oil and gas fields for CO_2 sequestration may face several potential limitations compared with aquifer or other disposal options. These disadvantages include:

- **Availability.** Aquifers are geographically more widespread than depleted oil & gas fields. Nearly all countries have aquifers, whereas few have large petroleum fields. Aquifers are more likely to be conveniently located close to large anthropogenic CO_2 sources. The solution is to transport CO_2 via long-distance pipelines. Such transport has been conducted commercially on a large scale for more than a decade in the southwestern U.S., both for naturally occurring, high-pressure CO_2 but also for anthropogenic waste CO_2 from gas processing facilities. We have estimated such transport costs in our economic model discussed in Section 6.0.

- **Organizational Conflicts.** There should be relatively few operational, legal, or other conflicts associated with CO_2 injection into non-potable aquifers. This is largely because currently there are no other commercial uses of saline aquifers. In contrast, significant conflicts would be expected between oil & gas operators or rights holders and CO_2 sequestration activities. For example, under normal market conditions (i.e., no sequestration credits), an oil field operator focuses on maximizing oil production and minimizing production costs; this tends to reduce CO_2 sequestration.

1.3 Previ ous Work

Research into geological sequestration of carbon dioxide is still at an early stage. Since 1993, several studies have examined the technical feasibility of sequestering CO_2 in depleted oil and gas fields, although these studies varied widely in focus and scope. Each study generated a preliminary estimate of the magnitude of potential sequestration capacity, although these estimates are not always directly comparable. These studies provided a valuable basis for the current study and are briefly summarized here, including comparison of their overall scope and results vis-a-vis the analysis performed by ARI.

The previous studies include: Winter and Bergman (1993) for abandoned oil and gas fields in the United States; Padamsey and Railton (1993) and related articles for depleted oil and gas fields in Western Canada; van der Meer and van der Straaten (1993) for worldwide depleted oil and gas fields; and Taber (1994) for worldwide EOR potential.

Winter and Bergman (1993) estimated the currently available CO_2 sequestration potential within abandoned oil and gas fields in the United States. In their analysis, they explicitly excluded depleted fields that still maintain even a limited level of active oil and gas production. This screening step filtered out the bulk of depleted oil and gas fields, intentionally targeting the small subset of entirely abandoned fields that could be available for immediate CO_2 sequestration. (In fact, synergy between remaining waterflood operations and future CO_2 flooding could be combined to reduce operating costs.) For this and other reasons, their estimate of current sequestration capacity is (understandably) much smaller than the more inclusive and time-independent ARI estimate.

The authors screened a Petroleum Information, Inc. production data base to identify known petroleum fields that were not productive during the previous 3 to 12 months. They assumed that these reservoirs had been abandoned as uneconomical and that they would be immediately available for CO_2 disposal. The cumulative volume of oil, gas, and water produced from these depleted fields was assumed to be available for CO_2 sequestration. However, using the cumulative volume of oil, gas, and water produced from depleted fields to estimate the volume available for sequestration would greatly over state the potential volume available if the estimate did not account for injected water, which is often not reported. It is not uncommon to inject (and consequently produce) multiple reservoir pore volumes of water during the life of a waterflood.

A minimum depth of 900 m was specified, below which reservoir pressure is generally adequate for supercritical CO_2 storage. A maximum depth cutoff of 3,300 m was also used, below which compression costs were assumed to be prohibitive. They anticipated that CO_2 could be injected until initial reservoir pressure was re-established; this pressure was inferred from field depth using an average pressure/depth gradient of 0.105 Bar/m (0.465 psi/ft), approximately 7% above the hydrostatic pressure gradient. Reservoir liquids were assumed to be incompressible and gas to behave as a perfect gas, such that volumes of gas and liquid are additive; dissolution of gas into water or oil was not considered.

Using this methodology, Winter and Bergman identified 1,360 individual abandoned oil and gas fields in the U.S. Total, immediately available CO_2 sequestration capacity was estimated to be approximately 800 billion m^3 (1.5 Gt; 23 Tcf). Most identified fields were relatively small, with sequestration capacity of less than 1 million t CO_2. The study did not estimate the costs of CO_2 sequestration in these fields.

Discussion. It is not possible to directly compare our study with Winter and Bergman, 1993. The ARI estimate of CO_2 sequestration in depleted U.S. oil and gas fields of 52,000 billion m^3 (98 Gt or 1,853 Tcf) is some eighty times larger than that of Winter and Bergman. This is primarily because: a) we included all known oil and gas fields; b) we further include all future undiscovered oil and gas fields; and c) our estimate is independent of timing or availability.

Concerning natural gas reservoirs, we largely agree with Winter and Bergman's decision to limit their estimate to only abandoned fields. This is because CO_2 injection into active gas fields would rapidly contaminate any remaining natural gas reserves. We would further caution that higher natural gas prices or improved gas extraction technologies could in the future stimulate re-development of currently uneconomical natural gas fields, thus CO_2 should be injected only into the most thoroughly depleted gas reservoirs. This could reduce the volume of immediately available CO_2 sequestration capacity in natural gas fields.

However, we do not consider that CO_2 injection is incompatible with current or future oil production operations. In fact, CO_2 injection can elicit beneficial enhanced oil recovery from certain depleted or abandoned oil fields, as demonstrated by extensive and growing CO_2-enhanced oil operations in the U.S. (see Section 2.0). For this reason, we consider that the Winter and Bergman analysis underestimated CO_2 sequestration in depleted oil fields.

Padamsey and Railton (1993). The Alberta Oil Sands and Research Authority (AOSTRA) conducted a study of CO_2 sequestration in selected depleted oil and gas fields in Western Canada (Alberta and Saskatchewan). This study was summarized in Padamsey and Railton (1993), Todd and Grand (1993), as well as other articles. We discuss the implications of this study in more detail in the Canada portion of Section 5.0.

AOSTRA performed a rigorous, integrated study involving detailed reservoir and cost analysis of five representative depleted oil fields and one gas field in Western Canada. Carbon dioxide injectant was assumed to be captured from anthropogenic sources, such as power plants, and then compressed and transported to the oil fields for underground injection. Enhanced oil recovery was modeled in the five fields using reservoir simulation. In summary, AOSTRA estimated that about 278 million tonnes of CO_2 could be sequestered in Western Canada over the next 15 years at an average net cost of C$46.50/tonne (1992 Canadian dollars). Costs were high largely because CO_2 was assumed to be captured from anthropogenic sources. The use of natural CO_2 injectant (if available) at one-fifth the supply cost of captured CO_2 would have allowed most of the projects to sequester CO_2 at a net profit.

With certain modifications (most important, adopting a more "typical" CO_2/EOR ratio of 6 Mcf/BO rather than the highly optimistic 3 Mcf/BO assumed in the AOSTRA study), we have incorporated the detailed evaluations of these six depleted Western Canadian fields into our worldwide assessment. We then projected EOR performance that they predicted to other depleted oil and gas fields in this large geologic province.

Van der Meer and van der Straaten (1993) discussed the physical processes that occur in reservoirs as a result of CO_2 injection. They assessed many of the design and operational challenges of storing CO_2 in depleted oil and gas fields. The study examined safety, stability, reservoir contamination, and other important issues. Particular attention was focused on the specific requirements for capturing and injecting flue gas from a conceptual 500-MW power station in northwestern Europe. The study provided general discussion of CO_2-flood well configuration, surface facilities, and costs, although data from the numerous CO_2-EOR projects in the United States were not extensively utilized.

This study also developed the first estimate of the total CO_2 storage potential in worldwide depleted oil & gas fields, albeit at a highly aggregate level. For each continent, a single estimate was reported of the ultimate void space in depleted reservoirs that could become available for CO_2 injection. Reservoir depth and pressure were apparently assumed to be constant, as was the compressibility of CO_2 relative to that of methane. Actual variability in reservoir size and depth, CO_2 compressibility, enhanced oil recovery efficiency, undiscovered petroleum potential, and costs/economics were not explicitly addressed in their worldwide estimate. Nevertheless, their estimate of 670 Gt of total CO_2 sequestration potential is of the same order of magnitude as the 923 Gt estimated in the current ARI study, which utilized different data sets and followed a different methodology (discussed briefly in the following paragraphs, and in more detail in Section 6.0).

Taber (1994) performed a pioneering study of the CO_2 sequestration potential in the subset of worldwide depleted oil fields that are believed to have CO_2-EOR potential. The study explained the CO_2-EOR process, set forth reservoir screening criteria for identifying EOR candidates, and systematically quantified the worldwide potential for CO_2 sequestration in EOR projects. We have used this study as a foundation in performing the current, expanded scope of work as defined by the IEA Greenhouse Gas Programme.

However, the current ARI study -- which should still be considered to be an approximate and highly preliminary estimate of global sequestration potential in depleted petroleum fields -- goes significantly beyond the scope of the Taber (1994) and other studies in several regards. We have been asked to consider significant sequestration capacity that was not quantified by the Taber study, which focused on the "low-hanging fruit" of oil fields with EOR potential. Our candidate reservoir set is more inclusive than those of previous studies, in that we placed no timing restrictions or cost ceilings on sequestration capacity. For example, depleted fields that may only become available late in the 21st century could still be valuable sequestration sites and thus are included in our analysis. All potential oil and gas field settings (even high-cost) are included. Finally, we have attempted a more detailed economic evaluation of CO_2 sequestration potential.

To better illustrate the scope of the current ARI study, the following summarizes the following principal differences between the current study and previous studies, particularly Taber (1994):

- **Natural Gas Fields:** The ARI study adds sequestration in depleted natural gas fields to the depleted oil fields covered in the Taber study. Like the van der Meer and van der Straaten (1993) study, we assumed that CO_2 could be injected to fill the void space in depleted gas fields. However, rather than assuming a fixed CO_2 density underground (650 kg/m^3), we computed actual density as a function of depth, using formation volume and compressibility factors. We found that the CO_2/CH_4 volumetric ratio is not fixed, but rather varies several-fold as a function of average reservoir depth.

- **Depleted Oil Fields:** We have included the application of immiscible CO_2-EOR potential in depleted oil fields (in addition to the miscible-only resources assessed by Taber, 1994).

- **Undiscovered Oil and Gas Fields:** Rather than restricting the study to a static list of known oil fields, we have included future worldwide oil and gas discoveries forecast by recent U.S. Geological Survey resource assessments. Undiscovered oil and gas fields are, by definition, not yet identified. However, the probabilistic analysis used by the USGS and other groups shows that undiscovered fields are statistically likely to be found during future decades, even in the most mature petroleum provinces.

- **Cost/Sequestration Curve:** We adapted methodology developed in a previous study of the economics of CO_2 sequestration in deep coal seams (Stevens and Spector, 1998), to estimate CO_2 sequestration costs and volumes for each major worldwide petroleum field group or resource region. This enabled us to develop the first (albeit highly preliminary) "cost/sequestration curve" for depleted petroleum fields.

- **Barriers:** We have examined some of the technical and non-technical barriers to CO_2 sequestration in depleted oil and gas fields, drawing on the experiences of both the EOR and underground gas storage industries.

The changes in scope, methodology, and new resource information led us to estimate a significantly larger CO_2 sequestration potential in worldwide depleted oil and gas fields compared with Taber (1993) and van der Meer and van der Straaten (1993), as summarized in **Table 1-1.** The ARI estimates are larger, even though in certain regards (notably EOR recovery factors) we have used more conservative assumptions.

Table 1-1: Comparison of Recent CO_2 Sequestration Capacity Estimates For Worldwide Depleted Oil & Gas Fields (Gt CO_2)

Estimate (Gt CO_2)	**van der Meer (1993)**	**Taber 1994**	**Current Study**
Depleted Oil Fields/EOR	148	61	126
Depleted Gas Fields	521	Na	797
Total	**670**	**Na**	**923**

1.4 Physical Properties of CO_2 Within Oil & Gas Reservoirs

In this section, we briefly introduce CO_2 flood processes within oil and gas reservoirs. (A more detailed discussion on this topic appeared previously in Taber, 1993.) The emphasis here is on relatively complex enhanced oil recovery processes, more than the simpler injection and storage of CO_2 into a reservoir. We believe that this emphasis is justified, given that EOR has the unusual capability of achieving low-cost or even profitable sequestration of CO_2 and thus warrants particular attention.

Carbon dioxide can exist in four distinct phases – vapor/gas, liquid, solid, and supercritical – depending upon temperature and pressure (Schoeling, 1998). Oil and gas operators generally handle CO_2 in its supercritical phase, which is stable above the critical point of 6.9 MPa (1087 psia) and 31° C (88° F). In its supercritical state, CO_2 may be considered to be a fluid, wherein the terms gas and liquid lose their conventional meaning. In general terms, the supercritical phase behaves like a liquid with respect to density, and like a gas with respect to viscocity.

Sequestration of carbon dioxide within an oil and gas reservoir is affected by the physical properties of CO_2. The key physical properties of CO_2 and their effects within the reservoir include:

- ***Density:*** Higher pressures increase CO_2 density, but much more gradually for supercritical vis-a-vis gas phases. For optimum enhanced oil recovery and sequestration, CO_2 density should be similar to that of oil within the reservoir. Otherwise, it may override the oil zone, leading to premature breakthrough to the production wells and poor oil recovery **(Figure 1-1**).

- ***Minimum Miscibility Pressure (MMP):*** This is the pressure at which CO_2 has the same density as oil. At pressures above the MMP, miscibility is achieved, along with dramatically improved oil recovery (**Figure 1-2**).

- ***Viscocity:*** At typical reservoir temperatures, the viscosity of CO_2 is more gas-like than liquid. The lower viscocity of CO_2 compared with oil can lead to unfavorable viscous fingering within the reservoir.

- ***Solubility in Water:*** The solubility of CO_2 increases directly with pressure (which can be operationally controlled), but inversely with temperature (which generally cannot). Dissolved salts impede CO_2 solubility. Conversely, water also dissolves in CO_2, thus the importance of dehydration prior to transporting CO_2 in a pipeline or reinjecting it into the reservoir, to prevent condensation and corrosion problems.

Figs 1-1 and 1-2

- ***Compressibility:*** At the elevated pressures typically encountered in underground reservoirs, molecular interactions cause non-ideal behavior of gas via the compressibility factor, which is determined experimentally. Compressibility is highly dependent on temperature and pressure, and generally ranges from 0.3 to about 0.6 for most reservoir conditions.

- ***Compositional Factors:*** The CO_2 may mix with other gases, such as light hydrocarbons or nitrogen, altering its physical properties.

1.5 CO_2-Flood Enhanced Oil Recovery

In most oil and gas fields, only a small proportion (typically 10-40%) of original oil in place (OOIP) is recovered using standard petroleum extraction methods. Carbon dioxide injected into a suitable depleted oil reservoir can achieve enhanced oil recovery through two processes, miscible or immiscible displacement. Miscible processes are more efficient and most common in active EOR projects, but immiscible flooding is likely to be increasingly important if widespread CO_2 sequestration takes place in depleted oil fields with sub-optimal reservoir conditions for miscible flooding.

- **Miscible** CO_2 Displacement: Under suitable reservoir pressure and oil density conditions (generally deeper than 1,200 m with oil lighter than 22° API gravity), injected carbon dioxide will mix thoroughly with the oil within the reservoir such that the interfacial tension between these two substances effectively disappears (Taber et al., 1997). Theoretically, all contacted oil can be recovered under miscible conditions, although in practice recovery is usually limited to about 10 to 15% of OOIP. Most of the case example projects discussed in Section 3.0 utilize miscible processes.

- **Immiscible** CO_2 Displacement: When reservoir pressure is too low and/or oil gravity too dense, the injected carbon dioxide remains physically distinct from the oil within the reservoir. However, injected CO_2 still can improve oil recovery by causing the oil to swell, reducing the oil's density and improving mobility. Currently only one large EOR project, Turkish Petroleum Co.'s Bati Raman field, utilizes immiscible processes, while several other smaller immiscible EOR projects are underway in the U.S. Although less efficient, immiscible displacement could be readily expanded if CO_2 sequestration is implemented on a large scale in depleted fields.

Once oil is mobilized by CO_2, or freed from its residual saturation state that normally locks it in place within the reservoir, it must be either pushed or pulled to the production well. For improved oil recovery, CO_2 injection frequently is alternated with water injection in a water-alternating-gas (WAG) process. In practice, a "slug" of injected CO_2 is repeatedly alternated with water drive, over intervals ranging from several weeks to months (**Figure 1-3**).

Figure 1-4 illustrates the typical surface configuration of an enhanced oil recovery project, while **Figure 1-5** shows the linkages of the field to CO_2 supplies and petroleum markets. Carbon dioxide from natural or anthropogenic sources is transported to the field via a dedicated pipeline and injected via a CO_2 injection well. Oil, water, natural gas, and carbon dioxide are produced by a production well and then these fluid components are separated at the surface. Oil and natural gas is collected and sold. Waste water is processed and then reinjected in a water disposal well. Carbon dioxide is separated, compressed, and recycled back into the formation in the CO_2 injector well. The life span of a typical CO_2-EOR project is in the range of 5 to 30 years, depending on a variety of technical and economic variables, such as the ratio of CO_2 injection to oil recovery, market prices of oil and the CO_2 injectant, operational costs, and other factors.

1.6 Sequestration in Natural Gas Fields

In addition to depleted oil fields discussed in Section 1.5, depleted natural gas fields also may provide technically feasible sites for CO_2 sequestration. However -- as modeled in some detail in Section 6.2 -- CO_2 sequestration in depleted gas fields almost certainly will be much more costly vis-a-vis sequestration in depleted oil fields. In favorable settings, EOR can offset much of the costs of CO_2 injection in depleted oil fields. In contrast, little or no offsetting benefit is generated by injecting CO_2 into depleted gas fields. Indeed, CO_2 injection in depleted gas fields can contaminate and reduce the value of remaining natural gas resources. Although injected CO_2 may improve recovery of light liquid hydrocarbons that frequently are associated with "wet" natural gas deposits, this benefit would more than be offset by breakthrough of CO_2 to the field's natural gas production wells, necessitating costly separation.

Nevertheless, depleted gas fields offer significant advantages over some other disposal methods, such as aquifer sequestration. First, unlike most aquifers, depleted gas fields are demonstrated long-term gas storage sites. Second, their geologic and reservoir characteristics usually are better understood than those of aquifers, thanks to an abundant well and production data base. And third, practical gas injection, monitoring, and operating technologies and experience originally developed for underground gas storage (UGS) operations may be readily adapted to facilitate sequestration in depleted gas fields.

Natural gas delivery systems typically comprise three principal components: 1) gas production fields; 2) long-distance pipelines; and 3) gas storage fields near demand centers. Because gas demand and prices fluctuate seasonally in temperate climates, UGS is often efficient for technical and economic reasons. Most pipeline systems operate gas storage fields, which are filled during low-demand/low-price periods (northern hemisphere summer), and then drawn down during peak-demand/high-price periods (winter).

For example, during 1997 a total of about 79,000 million m^3 (2.8 Tcf) of methane was safely injected and withdrawn in 910 individual natural gas storage fields in the United States (AGA, 1999). Assuming an average storage depth of 1,500 m, and thus a compressibility factor of 2.3 (**Figure 6-1**), this gas volume is equivalent to approximately 340 million tonnes of CO_2.

Underground storage has been an integral part of natural gas production, transportation, and distribution systems for many decades, particularly in North America, Europe, and Australia. Natural gas is routinely injected, stored, and withdrawn from hundreds of UGS fields. Consequently, the technologies for monitoring injected gas within depleted natural gas fields are relatively mature and could be readily adapted to monitoring and verifying CO_2 sequestration in these settings.

UGS technology provides valuable technical and cost data for CO_2 sequestration in depleted natural gas fields. Most commonly, the natural gas storage site was converted from an abandoned gas production field. Prior to conversion to a storage function, detailed reservoir and technical studies are routinely carried out on the abandoned gas field to establish its performance and integrity as a gas storage site. Because gas storage fields represent sizable capital investments of $100 to $1,000 million or more, petroleum engineers need to first establish the integrity of the seal, the reservoir storage mechanisms, and the optimal gas injection and operation procedures before conversion can go forward. The same evaluation methods that are used to screen gas storage candidates can be readily adapted to evaluate and rank potential CO_2 sequestration sites.

Additional information and analysis on natural gas storage as an analog for CO_2 sequestration in depleted gas fields is presented in Sections 2.4 and 3.8.

Fig 1-3

Fig 1-4

Fig. 1-5

2.0 Worldwide CO_2-Enhanced Oil Recovery & Gas Storage Industries

2.1 Overview of Worldwide CO_2-EOR Activity

Much of the analytical basis of this report relies on the empirical performance of commercial carbon dioxide enhanced oil recovery (CO_2-EOR) projects. Although none of these projects has yet been monitored specifically for the purpose of verifying CO_2 sequestration (plans are underway for joint EOR and sequestration monitoring at several new projects in Canada and Norway) – nonetheless, it is clear that significant sequestration is a normal consequence of CO_2-EOR floods.

Together the EOR projects that have been active during the past several decades offer a unique and diverse data set of long-term CO_2 injection into depleted oil and gas fields. These commercial projects provide valuable insights into the physical processes relating to CO_2 injection, production, processing, recycling, and (inferentially) sequestration within depleted oil and (associated) gas fields that encompass a variety of underground reservoir settings, as well as the costs and economics of sequestration.

This section presents information on current and past CO_2-flooding activity for enhanced oil recovery in mature oil and gas fields. The purpose of this discussion is to provide first an overview of the operational history and performance of worldwide commercial CO_2-EOR operations. Following the overview in Section 2.0, six individual field case histories of CO_2-EOR operations are presented in Section 3.0. These detailed case studies provide more specific information and insight into the variety of geological reservoir settings, CO_2 sources (natural and anthropogenic), types of operating companies and their strategies, production technologies employed, and other key variables that are likely to be crucial for future sequestration of carbon dioxide in depleted oil and gas fields.

Commercial CO_2-EOR operations currently take place in just four countries. In order of production, these are: the United States, Turkey, Trinidad and Canada (**Table 2-1**). In addition, several small projects were successfully operated in Hungary during the 1980's, but then abandoned during the mid-1990's. Worldwide CO_2-EOR production during 1998 is estimated to have averaged approximately 33,460 m^3/day (210,444 BOPD) from 79 individual projects, accounting for only a tiny fraction (0.3%) of total worldwide crude oil production of 10.7 million m^3/day (67.1 million BOPD) during this period.

The United States, which from the beginning has been the focus of CO_2-EOR technology development and investment, still accounts today for the overwhelming majority of worldwide CO_2 flooding operations. Total U.S. production during 1998 was estimated at 31,190 m^3/day (196,194 BOPD) of incremental enhanced oil recovery from 74 individual field projects. Turkey was second at 2,146 m^3/day (13,500 BOPD), essentially all from one large field. Trinidad and Canada had much lower production levels, 80 and 40 m^3/day (500 and 250 BOPD), respectively, from several small pilot fields. (A large CO_2 flood planned at Weyburn field in Saskatchewan is expected to boost Canada's production significantly during the next few years, but had not yet been implemented at report time.)

Table 2-1 : CO_2-EOR Production by Country (1998)

		CO_2-EOR Production	
Country	**Number of CO_2-EOR Projects**	**Barrels per Day (BOPD)**	**Cubic Meters per Day (m^3/day)**
United States	74	196,194	31,190
Turkey	1	13,500	2,150
Trinidad	2	500	80
Canada	2	250	40
TOTAL	**79**	**210,444**	**33,460**

(Generally, data concerning the specific volumes and rates of CO_2 injected into depleted oil fields for EOR are not publicly available. This section primarily reports information on enhanced oil recovery, which operators are required to report to state-level regulatory agencies in the United States. Most of the CO_2 injection data used in this study was gathered from case studies reported in the technical literature or directly from EOR operators. Later in Section 4.0, we discuss our methodology for projecting this subset of data to estimate CO_2 injection and sequestration in all EOR projects, and further estimating the sequestration potential of depleted oil and gas fields.)

2.2 United States CO_2-EOR Development

Current Status. The United States, where the technology for CO_2 enhanced oil recovery was first demonstrated on a large scale, remains by far the world's most active area for CO_2-EOR development and production. During 1998, enhanced oil recovery from 74 individual CO_2 floods in the U.S. averaged approximately 31,190 m^3/day (196,194 BOPD) (**Figure 2-1).** Most (53) of these CO_2 floods are located in the southwestern U.S., within the mature Permian basin of western Texas and eastern New Mexico, where numerous depleted oil fields exist and reservoir properties are often suitable for CO_2 miscibility (**Map 2-1**). The Permian basin has been the worldwide center of CO_2-EOR technology development and application. Much of the data and analysis developed for this study regarding EOR performance and potential CO_2 sequestration was based on the large, long-term CO_2-flood projects that have been active in the Permian basin (**Map 2-2**).

Other U.S. CO_2 floods are located in the Rocky Mountain region (6 projects), Mid-Continent region (8 projects), and coastal onshore Gulf of Mexico (5 projects). In addition, two large-scale hydrocarbon-miscible EOR floods located on the North Slope of Alaska utilize CO_2-rich (an estimated 22%) hydrocarbon gas, which is re-injected to maintain reservoir pressure and maximize crude oil production (McGuire et al., 1998).

Fig 2-1 and Map 2-1

Map 2-2

(Although the relative contribution of the CO_2 component vis-a-vis hydrocarbon gas in eliciting enhanced oil recovery from the reservoir has not been publicly assessed for these Alaskan projects, we have assumed that 22% of the EOR production in Alaska could be considered to be CO_2 related.) Altogether in the United States, CO_2 floods accounted for about 3.1% of total national crude oil produced during 1998.

Most CO_2-EOR projects utilize naturally occurring carbon dioxide, which is produced from high-pressure, high-purity underground deposits. For example, Shell's McElmo Dome field in southwestern Colorado contains over 283 million m^3 (10 Tcf) of proved CO_2 reserves at a pressure of about 2,000 psi. However, a small but significant fraction of EOR projects utilize anthropogenic CO_2 sources, such as waste streams from fertilizer or gas processing plants (**Table 2-2**).

Table 2-2: Active U.S. CO_2-EOR Projects that Utilize Anthropogenic Waste CO_2

State	Plant Name(s)	Plant Type	CO_2 Supply (MMcfd)	(10^6 m^3/d)	EOR Fields	Operator
Texas	Mitchell, Gray Ranch, Puckett, Terrell	Gas Processing	250	7.08	SACROC Crossett	Pennzoil, Altura
Colorado	LaBarge	Gas Processing	150	4.25	Rangely	Chevron
Oklahoma	Enid	Fertilizer	35	0.99	Purdy	Occidental
Louisiana	Koch	Gas Processing	25	0.71	Paradis	Texaco
	Total		**460**	**13.03**		

CO_2-EOR production is concentrated within a small number of extensive, highly productive projects that account for most EOR production in the United States, along with essentially all of Turkey's EOR production **(Table 2-3).** Just five large projects account for about half of total worldwide CO_2-EOR production. This concentration underscores the importance of focusing R&D investment into depleted-field sequestration on large current projects, particularly those with significant expansion potential to adjacent depleted oil and gas fields, to achieve the maximum near-term impact.

Table 2-3 : The Five Largest Active CO_2-EOR Projects Account for Half of Worldwide Production (1998)

Operator	Field	Basin	Area (km^2)	Wells Prod	Wells Inj.	EOR Production BOPD	EOR Production m^3/d	Gross Cum. CO_2 Injected Bcf	Gross Cum. CO_2 Injected 10^9 m^3
Altura	Wasson (Denver)	Permian	177	735	365	30,700	4,900	1,683	47.7
Amerada Hess	Seminole (Main)	Permian	64	408	160	30,000	4,800	NA	NA
Chevron	Rangely (Weber)	Rockies	61	204	200	13,881	2,200	811	23.0
Turkish Petrol.	Bati Raman	SE Turkey	44	145	41	13,500	2,150	NA	NA
Mobil	Salt Creek	Permian	49	85	48	12,000	1,900	NA	NA
Total 5 Largest Projects						**100,081**	**15,950**		

Historical and Projected Future Development. Commercial injection of carbon dioxide for enhanced oil recovery began at SACROC field in the Permian basin in 1972 (see detailed case study in Section 3.0). CO_2 flooding was later implemented at depleted oil fields in the Rocky Mountain, Mid-Continent and Gulf Coast, involving new types of reservoir formations (predominately sandstone rather than the carbonate reservoirs prevalent in the Permian basin). CO_2-EOR projects also were implemented on a smaller scale in Turkey, Canada, Hungary, and Trinidad during the 1970's and 1980's.

EOR production grew modestly in the U.S. throughout the 1970's and early 1980's, but then accelerated markedly during the late 1980's and 1990's, even in the face of low to moderate oil prices and overall reductions in upstream capital spending. Development was able to increase despite low oil prices for three main reasons: a) EOR development and operating costs fell, as technological advances continued to make field operation and monitoring more efficient; b) CO_2 supplies increased with the construction of new long-distance pipelines; and c) Oil companies (particularly the Majors) become organizationally leaner and more efficient operators. Limited fiscal incentives for enhanced oil recovery projects in the United States also had a favorable, albeit much more modest, impact on investment. CO_2-EOR production in the U.S. increased eight-fold from less than 4,000 m^3/day (25,000 BOPD) in 1985 to 31,000 m^3/day (196,000 BOPD) by 1998 (**Figure 2-2**).

Coincident with the growth in EOR, CO_2 deliveries to the Permian basin have grown markedly during this period (**Figure 2-3**). As discussed in Section 4.0, the vast bulk (an estimated 90%) of delivered CO_2 is effectively being sequestered within depleted oil fields in the Permian basin; only a small volume of this costly commodity has been allowed to escape to the atmosphere without recycling or reinjection. A small fraction of the Permian basin CO_2 supply has historically come from anthropogenic sources: waste CO_2 streams from four natural gas processing facilities in the Val Verde sub-basin. In contrast, most of the CO_2 supply in the Rocky Mountain and Midcontinent regions, the other main EOR areas in the United States, comes from anthropogenic sources.

Enhanced oil recovery from CO_2 flooding is expected to continue increasing in future years under most world oil price scenarios. As part of the U.S. Department of Energy's Oil and Gas Supply Model, which forecasts future oil and gas production in the United States, Advanced Resources developed an enhanced oil recovery submodule that specifically assesses the economics of CO_2-EOR projects in the United States. The field-based economic model evaluates the production costs of existing CO_2-EOR projects in the U.S., as well as the development costs for expanding CO_2 flooding into new depleted oil fields, providing the ability to systematically forecast future EOR production (Stevens and Kuuskraa, 1997). Alaskan CO_2-EOR production, which is not simulated in this model, was assumed to remain constant at the current level of about 2,400 m^3/day (15,000 BOPD).

Figs 2-2 and 2-3

Future EOR production will depend primarily on oil prices and technological improvements. Higher oil prices enhance revenues and profitability, leading to increased investment in EOR facilities and eventually higher levels of production (as well as associated sequestration). Technological improvements – such as improved flood monitoring using 4-d seismic surveillance -- lower extraction costs, which also enhances profitability, stimulating investment and increased production. To estimate future EOR production in the United States, we conducted a model run using USDOE's "Reference" (most likely) Oil Price track, and also assumed Reference technological advancement (USDOE, 1998). (This price track envisions the average price of oil in the continental U.S. increasing from US$13/bbl to $21/bbl over this period, in constant 1997$.)

Our forecasted scenario is based on current EOR market conditions, under which operators receive no financial benefit for sequestering CO_2. Currently, operators must cover the costs of purchased CO_2, as well as all other capital and operating costs, solely on the basis of sales of oil production. Should a market of tradable CO_2 emissions credits develop in the future, lower net operating costs would accelerate and intensify the development of EOR resources in the United States and worldwide.

Under the reference price/technology scenario, we forecast that CO_2-EOR production in the United States will remain relatively flat until 2010, after which higher oil prices and stimulate increased investment and production. Production is forecasted to increase to a peak about 35,000 m^3/day (220,000 BOPD) in 2015, before declining as the currently identified resource base becomes substantially depleted (**Figure 2-2).**

2.3 EOR Production Companies

Most of the firms involved with CO_2-EOR operations are "integrated" major oil companies, active in refining and marketing activities as well as production operations. Smaller independent (i.e., non-integrated) producers, which actually account for most oil production in the U.S., are generally less active in CO_2-EOR activities. Large oil companies tend to have the necessary expertise in engineering design and implementation of complex EOR projects. Although large EOR projects can add significant oil reserves, they often require more than 5 years to pay out, due to high operating costs and resulting low profit margins. EOR projects can be particularly vulnerable to periods of low oil prices. Large companies tend to have the relatively long-term investment viewpoint required for CO_2 floods to be economic.

A ranking of oil companies by CO_2-EOR production is provided in **Table 2-4. (**These data are reported by operator; actual ownership of produced oil may differ.) The largest producers include Altura (an alliance of Shell and Amoco that is limited to the Permian basin), Amerada Hess (which operates the large Seminole Unit in the Permian basin), and then Mobil, Arco (mainly through their Alaskan North Slope hydrocarbon-miscible projects), Chevron, Texaco, Exxon, Pennzoil, and Amoco (non-Altura production). All of these companies are large, integrated "Majors."

Table 2-4 : Production of CO_2-EOR by Company (1998)

	Percent		Number	CO_2-EOR Production	
Rank	of Total	Company	of Projects	BOPD	m^3/day
1	27%	Altura (Shell/Amoco)	13	55,928	8,892
2	14%	Amerada Hess	3	30,500	4,849
3	11%	Mobil	7	22,800	3,625
4	10%	ARCO (incl Alaska)	3	21,070	3,350
5	7%	Chevron	3	14,511	2,307
6	6%	Turkish Petroleum Co.	1	13,500	2,146
7	5%	Texaco	5	10,270	1,633
8	4%	Exxon	4	9,250	1,471
9	4%	Pennzoil	1	9,000	1,431
10	3%	Amoco	4	7,030	1,118
	8%	Other U.S./Worldwide	35	16,585	2,637
	100%	**TOTAL**	**79**	**210,444**	**33,459**

Source: Oil & Gas Journal, 1998; operator data.

To encourage private-sector development of EOR resources, the U.S. Department of Energy (USDOE) has taken an active role in promoting industrial R&D into advanced CO_2-EOR production technologies and innovative applications within new reservoir types and settings. For example, the USDOE provided cost share to Chevron and Advanced Resources International, Inc. to evaluate and implement a pilot demonstration of CO_2 flooding into the siliceous shale reservoirs of the Monterey Shale within California's San Joaquin Valley, a reservoir and rock type that has never been proven to be amenable to CO_2 flooding (Chevron, 1998). If successful, this technology could be expanded to an entirely new reservoir type with approximately 16 billion m^3 (100 billion barrels) of EOR potential. An additional, although initially unintended, benefit of this R&D could be providing a low-cost (or potentially profitable) underground disposal site for anthropogenic CO_2 emissions in California.

It is important to point out that our sequestration study assumes current levels of technology and costs. Technological progress in EOR and sequestration methods, promoted by industrial R&D projects such as the Chevron project discussed above, undoubtedly will occur in the future, increasing efficiency while reducing costs.

Although smaller independent oil companies remain minor players in CO_2-EOR, in recent years they have become increasingly active, particularly in CO_2 flooding of relatively small properties. Some of the leading smaller companies currently involved in CO_2-EOR include JP Oil, Mitchell Energy, and Wiser Oil. This trend has in part been aided by technology transfer and, on occasion, financial assistance provided by the U.S. Department of Energy.

In addition, Shell CO_2 Co., the largest supplier of injectant in the Permian basin, has also targeted independent producers in the Permian basin and other areas to increase the market demand for CO_2. For example, Shell conducts short courses and seminars in CO_2-EOR technology aimed at the engineering staff and management of independent oil producers. Shell CO_2 Co.'s technical staff also helps to screen reservoir candidates, using reservoir and economic models they have developed, and to design appropriate flooding programs for independents. On occasion, Shell has shared some of the risk that operators undertake in implementing a CO_2 flood – such as lower future oil prices or the technical risk of lower-than-expected oil production -- by contracting to supply CO_2 to the project at a reduced cost in return for an equity share in the enhanced oil production stream. CO_2 supply costs have also been linked to oil prices, which again reduces operator risk. Shell's entrepreneurial approach has helped to expand CO_2 flooding in the United States during the 1990's, even during a period of low-to-moderate oil prices.

2.4 Overview of Underground Gas Storage Technology & Activity

Overview. In addition to CO_2 enhanced oil recovery operations, the injection and storage of natural gas within underground formations is another commercial petroleum industry activity that can provide useful insights into the technical feasibility and costs of CO_2 sequestration in depleted oil and gas fields. This section briefly introduces and quantifies worldwide underground gas storage (UGS) activity, while Section 3.8 provides a representative case history of a gas storage field. Certain cost components for UGS were used in the cost/sequestration analysis presented in Section 6. Finally, because the injection and storage of combustible natural gas underground arguably could be considerably equally or more hazardous than storing inert CO_2, we discuss insights gained from the experience of the UGS industry within the Barriers Section 8.0.

Underground gas storage is used to accommodate seasonal swings in gas demand, which are usually caused by weather-related variations in residential and industrial heating requirements. UGS is often a less expensive and more responsive alternative compared with constructing larger diameter pipelines and drilling extra gas production wells. Gas storage is usually located close to major urban or industrial demand centers or strategic transcontinental pipeline hubs. Natural gas typically is purchased and injected during low-demand periods (Northern Hemisphere summer) and then withdrawn from UGS facilities during high-demand periods (winter).

Before a gas storage project can be implemented, a detailed feasibility study generally must be performed. Such a feasibility methodology could form the basis for studies of converting depleted oil and natural gas fields to CO_2 sequestration. The feasibility usually involves the following steps:

- Detailed geologic and geophysical mapping to define the storage capacity, geometry, and internal stratigraphic framework of the reservoir, as well as the nature of overlying, lateral, and underlying seals.
- Reservoir engineering analysis of well injectivity and production, reservoir fluid composition, pressure-volume-temperature state, and other parameters.
- Analysis of potential chemical reactions between injected gas and the host rock/fluid system.
- Reservoir simulation study involving history match of fluid production, design of optimal placement and operation of the injection/withdrawal wells, and a schedule for subsurface operations.
- Design of surface gas injection and withdrawal facilities, including well heads, compression, dehydration, water disposal, and gas gathering and distribution pipelines.
- Economic study of natural gas supply, demand, and pricing. Financial analysis of surface and subsurface capital and operating costs, including the cost of base gas.

UGS Activity. During 1998, a total of more than 500 UGS fields were in operation worldwide, representing total working gas storage capacity is some 164,000 million m^3 (5.8 Tcf; **Table 2-5**). The United States and Canada account for about two-thirds of the worldwide UGS capacity, whilst Europe accounts for most of the remainder. Underground gas storage is less prevalent in Australia and other temperate countries, where residential use of gas for heating accounts for only a minor portion of overall demand. New UGS facility design and construction is underway in China, South America and other regions, as well as in the more mature North American and European systems.

In addition to working gas volumes, UGS fields require base gas volumes that can range from 50% to 500% of the working gas volume (worldwide base gas data are not readily available). Thus, the actual total gas injected into worldwide UGS facilities is on the order of 300,000 million m^3 (10 Tcf). This volume is about double the estimated ultimate CO_2 sequestration of ongoing CO_2-EOR projects. Together, gas storage and EOR represent the largest industrial experience in gas injection into geologic formations.

Most underground gas storage facilities are converted depleted oil and natural gas fields. In the United States, where data are readily available, some 336 out of a total 406 storage facilities were converted oil and gas fields, compared with 51 purely aquifer (non-petroleum bearing) reservoirs (**Table 2-6**). (It should be noted that many oil and gas reservoirs are simultaneously strong aquifer systems.) Reservoir types are typically sandstone or carbonate lithologies; the use of salt caverns and abandoned coal mines for gas storage is much less common.

Table 2-5: Summary of Worldwide Underground Gas Storage Capacity (1998)

Country/Region	Number Of Fields	Gas Storage Working Capacity (million m^3)	(Tcf)
United States	406	92,349	3.26
Canada	11	14,580	0.51
Total North America	**417**	**106,929**	**3.78**
Germany	38	15,410	0.54
Italy	11	13,422	0.47
France	15	10,490	0.37
Other Europe	36	18,361	0.65
Total Europe	**100**	**57,683**	**2.04**
Total Australia	**4**	**1,244**	**0.04**
Worldwide Total*	**521**	**164,612**	**5.81**

Note: *Does not include Russia and CIS countries. Does not include LNG tanks or other surface storage. China, Japan, Korea, New Zealand currently do not have underground gas storage.

Sources: IEA, 1999 (non-U.S. data); AGA, 1999 (U.S. data)

Table 2-6: Underground Gas Storage in the United States (1998)

By Storage Site	Number Of Fields	Gas Storage Working Capacity (million m^3)	(Tcf)
Depleted Oil & Gas Field	336	79.5	2.81
Aquifer	51	9.4	0.33
Salt Cavern	18	3.4	0.12
Abandoned Coal Mine	1	0.06	0.002
Total	**406**	**92.3**	**3.26**
By Reservoir Type			
Sandstone	261	58.5	2.07
Carbonate	77	23.4	0.83
Cavern	19	3.5	0.12
Other/Not reported	49	6.9	0.25
Total	**406**	**92.3**	**3.26**

Source: AGA, 1999

UGS Technologies. Many of the technologies developed to evaluate, design, and operate underground gas storage have application to future CO_2 sequestration operations in depleted oil and gas fields. These technologies include:

- **Subsurface Safety Valves:** UGS wells with particularly high flow potential (such as salt cavern storage commonly used in Germany) require direct-control subsurface safety valves to meet current environmental and safety regulations (Gano and Revay, 1993).

- **Reservoir Management:** Many depleted gas and aquifer reservoirs have active drive. UGS management systems, particularly detailed reservoir characterization and numerical simulation, have been developed to optimize injection and withdrawal cycles (Hower et al., 1993).

- **Isotopic Tracers:** Natural and artificially injected isotopes are used in the UGS industry to track movement and mixing of isotopically different gases. Isotopes can help optimize well completions, identify reservoir compartmentalization, and allocate storage by individual reservoir layer. Gas storage fields are excellent "laboratories" for demonstrating the mixing of isotopically different gases and identifying gas seeps (Epps, 1992; Schoell et al., 1993).

- **Seismic Methods:** The use of advanced seismic reflection techniques, such as 3-D pressure and shear-wave seismic, is now used to image gas movement through petroleum reservoirs. 3-D seismic data collected over time (4-D) can define geologic facies, faults and fluid boundaries (Reymond et al., 1999; Huang et al., 1999).

- **Other Geophysical Methods:** Other geophysical methods, such as gravitational anomalies, can be used to track gas movement through the reservoir. For example, high-resolution surface and borehole gravimeters can define the areal distribution of gas within a reservoir, as well as the vertical distribution of gas and oil in a well (Brady et al., 1993).

3.0 Case Studies of CO_2-EOR and Underground Gas Storage Projects

3.1 Introduction

This section presents detailed case histories of seven depleted oil and gas fields. Because of the low costs and likely importance of CO_2-EOR technology for sequestration, we selected as case studies six depleted oil and gas fields with CO_2-EOR operational experience. We also selected one underground natural gas storage field as a case study of gas injection and withdrawal in a depleted natural gas field. These case studies provide useful insights into the feasibility and operational challenges of CO_2 sequestration in depleted oil and gas fields. Selected from the larger universe of hundreds of CO_2-EOR and gas storage projects currently in operation, the case studies also provide tangible evidence and reassurance of just how sophisticated and routine the injection and monitoring of CO_2 and natural gas into depleted oil and gas fields has become.

The projects discussed in this section include six EOR fields: three fields from two different regions of the United States, one EOR field in Canada, and one field in Turkey. We also briefly review the experience of CO_2 injection at several depleted oil fields in Hungary, which were active during the 1970's and 1980's, but were discontinued during the mid-1990's. We focus here on the larger and longer-lived projects, representing some geologic and geographic variety, to provide background on the actual performance and technology application in commercial fields, as well as insights into how future CO_2 sequestration projects may be designed and operated. Finally, we discuss an underground natural gas storage facility in the central United States that is considered to be representative of the more than 500 underground gas storage fields in operation worldwide.

Later in the report, the CO_2-flood potential of other major worldwide petroleum provinces is discussed. However, because most such areas lack actual CO_2 flood operations or even basic pilot field testing, this analysis is necessarily less detailed and more speculative.

No truly comprehensive case studies of CO_2-EOR floods have been published in the technical literature. Thus, for this study we had to piece together information and analysis based on the numerous quite focussed published accounts that are available, which tend to be limited to the specific performance of individual production technologies or strategies. We augmented this public information with discussions held with EOR field operating companies. Published accounts of natural gas storage case studies similarly tend to be limited, thus we selected a storage field where ARI recently performed extensive field testing and analysis.

The depleted oil and gas field case histories are:

- **(U.S.A.) Pennzoil's SACROC Unit**, the world's first large-scale CO_2 flood, located within the Permian basin of West Texas. SACROC produces from a depleted carbonate reservoir and has the longest history of CO_2 injection and EOR production. Most of the CO_2 injected into this field came from gas processing plants (anthropogenic), although the field has recently switched to natural CO_2 sources.

- **(U.S.A.) Shell's Wasson-Denver Unit**, also located within the Permian basin of West Texas, is currently the world's largest CO_2 flood in terms of enhanced oil production and CO_2 sequestered. This project involves injection of CO_2 from natural sources into a depleted carbonate oil reservoir.

- **(U.S.A.) Chevron's Rangely Weber Unit**, located in northwestern Colorado, is the world's third largest CO_2 flood. The anthropogenic CO_2 injectant used exclusively for this project comes from a gas processing plant. The geologic setting and reservoir type (sandstone) are characteristic of Rocky Mountain Foreland basins, distinctly different from the carbonate reservoirs of the Permian basin.

- (**Turkey) Turkish Petroleum Co.'s Bati Raman Field** is the largest CO_2-EOR project implemented outside the United States. Bati Raman produces relatively heavy oil from a carbonate reservoir, and represents an immiscible flood with characteristics considered outside the "normal" range for CO_2-EOR projects.

- **(Canada) Vikor Resources' Joffre Viking Tertiary Oil Unit** currently is the largest CO_2-EOR project in Canada. The Joffre Viking project utilizes natural gas plant CO_2 injectant -- an anthropogenic source -- and has been active on a small scale for 15 years.

- **(Hungary) Nagylengyel and Szank Fields** were CO_2 flooded using natural gas plant off-product and flue gas during the 1980's, also anthropogenically sourced, but have since been shut in.

3.2 SACROC EOR Unit (Pennzoil E & P Co.)

(Hawkins et al.,1996; Wingate, 1995; Brock and Bryan, 1989; operator discussions)

Background. Initiated in 1972, Pennzoil's SACROC Unit in the Permian basin was the world's first large-scale commercial carbon dioxide EOR flood. The SACROC (Scurry Area Canyon Reef Operators Committee) operation covers a 205-km^2 (50,000-acre) area within the depleted Kelly-Snyder oil field in the eastern part of the Permian basin, west Texas **(Map 2-2)**.

Light oil is produced mainly from limestone reservoirs of the Canyon Reef Formation of Late Pennsylvanian age. The field is internally complex. Tight shale zones vertically segregate the oil reservoir into numerous stacked compartments that are not in pressure communication; fluid flow is essentially horizontal. The SACROC Unit is the largest field within the Horseshoe Atoll geologic trend, an arcuate-shaped structure that holds enormous in-place oil resources and sequestration potential.

Primary oil production for the SACROC Unit began shortly after discovery in 1948. Secondary (waterflood) operations were initiated in 1954 to maintain oil production. CO_2 miscible flooding was implemented in 1972 and has proceeded continuously for 27 years.

During the period 1972 to 1995, CO_2 injectant for the SACROC project was supplied from nearby natural gas processing plants. These four natural gas plants (Terrell, Grey Ranch, Mitchell, and

Puckett) in the southern Permian basin separate naturally occurring CO_2 from natural gas production to enable the latter to meet methane pipeline corrosion specifications. Because the separated CO_2 byproduct otherwise would be emitted to the atmosphere, the CO_2 injectant used during this period may be considered as anthropogenic-sourced. High-pressure, pure CO_2 was transported to the SACROC field by a devoted 41-cm (16-inch) diameter, 270-km (170-mi) long pipeline operated by Canyon Reef Carriers (CRC). Pipeline capacity was about 6.8 million m^3/day (240 MMcfd), but actual transported CO_2 volumes averaged only 1.4 million m^3/day (50 MMcfd).

The source of CO_2 supply to SACROC changed in 1996. Delhi Pipeline Co. purchased the CRC pipeline and converted it to natural gas transportation service. Simultaneously, SACROC and the nearby North and South Cross fields converted to natural carbon dioxide injection supplied by Shell CO_2 Co. The gas processing plants in the Val Verde basin became isolated from market and the waste CO_2 was vented during 1996-1998. However, in September 1998 Petro Source Corp., MCNIC Pipeline & Processing Co., and ARCO Permian completed a new 25-cm (10-inch) diameter, 130-km (82-mi) long pipeline from the four Val Verde gas treatment plants to reconnect this supply of anthropogenic CO_2 to EOR fields in the Permian basin (Petroleum Engineer International, 1998). The Petro Source pipeline initially carries 2 million m^3/day (70 MMcfd) of CO_2, with capacity to transport up to 3.5 million m^3/day (125 MMcfd).

CO_2--EOR Performance. Significant EOR was achieved at SACROC from 1981 onwards **(Figure 3-1)**. This followed a 10-year period during which CO_2 injection (around 150 MMcfd) and water injection (rising from 200,000 to 600,000 BWPD) failed to avert a decline in oil production. The first part of the recognizable period of EOR (1981-1984) coincides with a sharp increase in water injection rate from 600,000 to over one million BWPD. It is not clear, therefore, how much of the incremental oil generated during this period is due to the more aggressive water flooding or to a delayed CO_2 effect. On the other hand, post-1984 water injection steadily declined to one quarter of its peak rate, and much of this incremental oil can be attributed to CO_2-EOR.

Carbon dioxide injection rates were much higher during the early stages of the project at about 5.1 million m^3/day (180 MMcfd), but declined to 1.7 million m^3/day (60 MMcfd) by 1995. A cumulative, gross total of just over 30 x 10^9 m^3 (1 Tcf) of injected CO_2 contributed to recovery of 69 million bbl of incremental oil. By 1995 the cumulative gross injection/production ratio (including re-injection) had declined to (a still relatively high) 15 Mcf/BO.

Table 3-1: Key Parameters of Pennzoil SACROC CO_2-EOR Project, Permian Basin, U.S.A.

Parameter	Metric Units	English Units
Depth	2,040 m	6,700 feet
Oil Gravity	0.82 g/cc	41° API
Current EOR Area	200 km^2	49,900 acres
Number of Wells	325 Producers, 57 CO_2 Injectors	
Original Oil in Place (OOIP) Current EOR Production	336 million m^3 1,430 m^3/day	2.113 billion barrels 9,000 BOPD
Estimated Ultimate EOR (%OOIP)	27 million m^3 (8.0%)	169 million barrels (8.0%)
Current Gross CO_2 Injection Rate	1.7 million m^3/day	60 MMscfd

Cumulative Gross CO_2 Injection (1996)	30 x 10^9 m^3 (0.06 Gt)	1.04 Tcf
CO_2 Source	Gas Processing Plant (1972-1995); Natural Source (1996-on)	

Note: 1 metric tonne CO_2 at U.S. standard conditions (1 atm and 60° F) = 534.76 m^3

Figs 3-1 and 3-2

EOR performance could be considerably better within certain portions of the SACROC Unit, particularly areas where waterflooding had been mature by the time CO_2 injection was started. In one area (603 acres, 24 wells), injection during the first 5 years led to an incremental recovery of 10% of the original oil in place (OOIP); gross CO_2 utilization was 9.5 Mcf/bbl and a net of only 3.2 Mcf/bbl. Results over nearly 7 years in a larger area (2,700 acres, 100 wells) show incremental recovery of 7.5% of OOIP; gross and net CO_2 utilization were 9.7 Mcf/bbl and 6.5 Mcf/bbl, respectively. Pennzoil estimates that CO_2 flooding will recover approximately 8.0% of original oil in place. Pennzoil has not undertaken studies to estimate CO_2 sequestration at the SACROC Unit.

3.3 Wasson-Denver EOR Unit (Altura [Shell/Amoco])

(Kittridge, 1992; Hsu et al., 1997; Oil & Gas Journal, 1998; Ward and Cooper, 1995; operator discussions)

Background. Altura, a local Permian basin joint venture between Shell and Amoco, operates the Wasson-Denver Unit project, one of the world's largest and longest-term CO_2 floods. The Wasson-Denver Unit covers about 114 km^2 (28,000 acres) in Yoakum and Gaines counties, western Texas (**Map 2-2**). Light oil is produced from the Denver Unit of the dolomitic San Andres Formation at a depth of about 1,500 m (5,000 feet). Lateral reservoir continuity is considered good across the average injector-producer distance of 300 m (1,000 feet).

The Denver Unit is located at the shallowest structural level within the Wasson field. The field has an original natural gas cap up to 100 m thick that has a significant impact on its CO_2-flood performance. Primary oil production dates back to 1936. Water flood operations commenced in 1965, while miscible CO_2 injection was initiated in mid-1983 and increased markedly following completion of the Cortez pipeline in mid-1984 (**Figure 3-2**). The Wasson-Denver Unit is operated as a water-alternating-gas (WAG) flood.

Carbon dioxide injectant is supplied to the Wasson-Denver Unit via the 900-km (560-mi) long, 76-cm (30-in) diameter Cortez pipeline. The Cortez line is operated by Shell CO_2 Co., Ltd. and is supplied by the McElmo Dome field in southwestern Colorado, which is a naturally occurring CO_2 deposit. During 1998, gross CO_2 injection rates at Wasson-Denver Unit averaged 9.3 million m^3/day (330 MMscfd). This rate is down considerably from the 12.1 million m^3/day (426 MMscfd) level during 1996, as part of the planned tapering of this maturing WAG. Approximately half of this CO_2 injectant is purchased from the Cortez supply pipeline, while the other half is sourced internally by recycling CO_2 that has broken through to the field's production wells (such CO_2 breakthrough is a normal occurrence in an EOR field).

CO_2-EOR Performance. The Wasson-Denver Unit CO_2 flood comprises an array of 365 injection wells and 735 producing wells. **Figure 3-2** shows the long-term oil production history since discovery in 1937, illustrating clearly the three distinct phases of recovery methods used at the field. Primary oil recovery took place during 1937-1963. Water flooding beginning in 1964 generated a significant increase in oil recovery, which began to drop off sharply after 1980.

The onset of CO_2 flooding in 1983 was accompanied by a sharp decline in water injection. Altura's analysis indicates that most of the oil production during the first few years of the CO_2 flood continued to be attributed to the base waterflood. Enhanced oil recovery first became evident in mid-1985 and steadily increased to the end of 1996, as demonstrated by the widening differential between the actual oil production curve and the projected base decline curve. The CO_2 flood was later expanded during 1989 into the western half of Wasson-Denver Unit.

Table 3-2: Key Parameters of the Altura (Shell/Amoco) Wasson Denver Unit CO_2-EOR Project, Permian Basin, U.S.A.

Parameter	Metric Units	English Units
Depth	1,585 m	5,200 feet
Oil Gravity	0.86 g/cc	33° API
Current EOR Area	115 km^2	27,848 acres
Number of Wells	735 Producers, 365 Injectors	
Original Oil in Place (OOIP)	335 million m^3	2.10 billion barrels
Current EOR Production	4,880 m^3/day	30,700 BOPD
Estimated Ultimate EOR (%OOIP)	56 million m^3 (16.6%)	348 million barrels (16.6%)
Current Gross CO_2 Injection Rate (1998)	9.3 million m^3/day	330 MMscfd
Cumulative Net CO_2 Injection (1998)	43 x 10^9 m^3 (0.08 Gt)	1.5 Tcf
CO_2 Source	Bravo and McElmo Domes (Natural)	

CO_2 injection rates during most of this period were fairly steady at around 13 million m^3/day (450 MMcfd), while EOR production increased to nearly 5,000 m^3/day (30,700 BOPD) by 1998, currently the highest of any active CO_2 flood. The cumulative net purchased CO_2 injected/EOR produced ratio at Wasson-Denver Unit to date is a relatively high 2,660 m^3/m^3 (15 Mscf/BO). However, Altura forecasts that CO_2 flooding eventually will recovery a total of 56 million m^3 (348 million barrels) or approximately 16.6% of original oil in place by the conclusion of this project. Thus, the net CO_2/EOR ratio is expected to decline to an ultimate 950 m^3/m^3 (5.34 Mscf/BO) at the end of the project, which is fairly typical for the Permian basin. Altura has not conducted specific studies of CO_2 sequestration at the Wasson-Denver Unit.

3.4 Rangely Weber Sand Unit (Chevron USA Production Co.)

(Jonas et al., 1990; Brock and Bryan, 1989; Hild and Wackowski, 1998; Wackowski, 1997; and Oil & Gas Journal, 1998; operator discussions)

Background. The Rangely Weber Sand Unit CO_2 flood operated by Chevron covers 15,000 acres in northwestern Colorado (**Map 3-1**). It is the largest oil field in the U.S. Rocky Mountain region in terms of daily and cumulative oil production, and is currently the world's third largest CO_2 flood. The project is developed as a miscible water-alternating-gas (WAG) flood. Although considered very profitable overall, the Rangely project is approaching the end of its planned life. Chevron plans to reduce and eventually cease new CO_2 purchases.

CO_2 injection and enhanced oil recovery takes place in the Weber Sandstone, a 200-m (675-ft) thick sequence of interbedded eolian sandstones and mixed fluvial siltstones, shales, and sandstones of Pennsylvanian-Permian age. Five major fluvial shale breaks have been identified within the reservoir. These shale layers generally act as effective vertical permeability barriers that stratify the reservoir into six major producing zones. Formation depths of about 1,800 m (6,000 ft) and the relatively light oil are suitable for CO_2 miscibility.

Map 3-1 here

CO_2 injectant at Rangely is supplied via pipeline from Exxon's La Barge natural gas processing plant in southwestern Wyoming. The massive Labarge gas plant removes naturally occurring CO_2 from natural gas production in this region, enabling the latter to meet pipeline corrosion specifications. Because this byproduct CO_2 otherwise would be emitted to the atmosphere -- in fact most of the waste CO_2 at this gas plant still is vented -- the injectant at the Rangely Weber Unit may be considered to be anthropogenic sourced. The delivered supply cost for high-pressure CO_2 at this field is not known, but is estimated to be in the range of \$0.02/m^3 (\$0.50/Mcf).

The Rangely Weber sandstone represents a different reservoir type (clastic) compared with the carbonate reservoirs typical of the Permian basin CO_2 floods, while the tectonic environment is also distinctly different (Rocky Mountain thrust belt vs. Permian basin passive shelf). This makes the Rangely EOR case study a useful complement to the Permian basin examples. We used the well-documented Rangely Weber EOR project to develop a methodology for estimating CO_2 sequestration in depleted oil fields, discussed in Section 4.0.

Table 3-3: Key Parameters of Chevron's Rangely Weber Unit CO_2-EOR Project, Colorado, U.S.A.

Parameter	Metric Units	English Units
Depth	1,680 to 1,980 m	5,500 to 6,500 feet
Oil Gravity	0.85 g/cc	35° API
Current EOR Area	62 km^2	15,000 acres
Number of Wells	378 Producers, 259 CO_2 Injectors	
Original Oil in Place (OOIP)	300 million m^3	1.88 billion barrels
Current EOR Production	2,210 m^3/day	13,881 BOPD
Estimated Ultimate EOR (%OOIP)	22 million m^3 (7.2%)	136 million barrels (7.2%)
Current Gross CO_2 Injection Rate	4.4 million m^3/day	157 MMscfd
Cumulative Gross CO_2 Injection (1996)	23 x 10^9 m^3 (0.04 Gt)	0.811 Tcf
CO_2 Source	Exxon Labarge Gas Processing Plant (Anthropogenic)	

CO_2-EOR Performance. The CO_2 flood comprises an array of 259 CO_2- and 21 water-injection wells and 204 producing wells, developed on an average 0.08 km^2 (20-acre) well spacing. Carbon dioxide injection was initiated in late 1986 as part of a WAG flood. It was anticipated in 1989 that gross CO_2 utilization would be 9 Mcf/bbl with a net of 4-6 Mcf/bbl, but actual utilization has been slightly higher. During the first ten years of CO_2 flooding (1986-1996), 674 Bcf of gross carbon dioxide was injected (317 Bcf net purchases) to produce 51 million bbl of incremental oil. Gross CO_2 utilization was 13.2 Mcf/bbl (6.2 Mcf/bbl net). Mid-1997 CO_2 purchases were 1.6 million m^3/day (55 MMcfd). Ultimate CO_2 purchases are predicted to be 13.4 billion m^3 (472 Bcf), for a highly favorable final net CO_2/oil ratio of 3.47 Mcf/BO.

A continual problem at Rangely Weber field has been maintaining CO_2 conformance, which is the ideal condition under which injectant flows evenly throughout the reservoir, achieving maximum oil sweep and recovery. In fact, CO_2 flows very unevenly through the Rangely Weber field (and many other CO_2 floods). This results in rapid effective sweep of oil in highly permeable zones, while the tighter zones remain unswept. Over time, injected CO_2 simply continues to flow through the permeable but barren "thief" zones, leading to premature CO_2 breakthrough at the production wells and bypassing considerable oil in place. (Rangely Weber field is further analyzed in Section 4.3 as a benchmark for CO_2 sequestration in depleted oil fields.)

3.5 Joffre Viking Tertiary Oil Unit, Alberta, Canada (Vikor Resources Ltd.; Alberta Oil Sands Technology and Research Authority)

(Stephenson, 1990; Stephenson et al., 1991; Oil & Gas Journal, 1998)

Background. Vikor Resources Ltd., with funding from the Alberta Oil Sands Technology and Research Authority, began Canada's first CO_2 injection pilot at the abandoned Joffre Viking field in 1984. This relatively small EOR operation is located near Red Deer, between Edmonton and Calgary in the western Canadian province of Alberta. Light oil is produced from the Joffre Viking sandstone reservoir at a depth of 1,550 m.

Primary oil production at the field dates back to 1953, with water flood operations commencing in 1957. The field had reached its economic limit by the mid-1960s with a relatively high 42% recovery of the 14.8 million m^3 (93 MMBO) original oil in place. Laboratory testing and reservoir simulation during the early 1980s predicted that tertiary oil recovery using a miscible carbon dioxide flood could be commercially viable. Currently, the Viking Unit is Canada's only significant CO_2-EOR project (although PanCanadian's Weyburn EOR project eventually will be far larger).

Table 3-4: Key Aspects of Vikor's Joffre Viking CO_2-EOR Project, Alberta, Canada

Parameter	Metric Units	English Units
Depth	1,550 m	5,100 feet
Oil Gravity Current EOR Area	0.82 g/cc 9.2 km^2	42° API 2,240 acres
Number of Wells	15 Producers, 5 Injectors	
Original Oil in Place (OOIP)	14.8 million m^3	93 million barrels
Current EOR Production	80 m^3/day	500 BOPD
Estimated Ultimate EOR (%OOIP)	NA	NA
Current Gross CO_2 Injection Rate	NA	NA
Cumulative Gross CO_2 Injection (1996)	NA	NA
CO_2 Source	Alberta Gas Ethylene Plant (Anthropogenic)	

CO_2-EOR Performance. The current CO_2 flood comprises three separate well patterns comprising a total of 5 water/CO_2 injectors and 15 producers that drain a surface area of about 9.2 km^2 (2,240 acres). In addition, a number of peripheral water injection wells are required to maintain reservoir pressure. Over the years, Vikor has experimented with a variety of injection strategies to determine the optimum oil recovery technique. These have included continuous CO_2 injection, continuous slug injection followed by waterflood, injection of alternate slugs of CO_2 and water (WACO_2) followed by waterflood, and simultaneous injection of CO_2 and water followed by waterflood. The WACO_2 process was found to give best recovery.

Operational problems included gravity override, as injected CO_2 effectively swept only the top one-third of the oil reservoir. Only about 50% of the formation was contacted due to gravity override and an adverse mobility ratio.

Sources of injection gas at Joffre field included gaseous CO_2 (>98% pure) from a nearby Alberta Gas Ethylene Company plant, trucked-in liquid CO_2, and recycled gas from the recovery wells. The only gas treatment required was dehydration, accomplished during compression of the CO_2 to injection pressure of 1,000-1,375 psi. On at least one occasion, operation of the pilot was curtailed by inadequate CO_2 supplies.

Limited operational information for the Joffre Viking CO_2 flood is available. Using a WAG injection process, some wells experienced a twenty-fold increase in oil production following the start of CO_2 injection early in 1984. By the end of 1989, about 42,000 m^3 of incremental oil had been produced from the earliest of the pilot patterns. Data through December 1990 indicate that each incremental barrel of oil produced required 4.9 Mcf of gross CO_2.

Retention of CO_2 in the reservoir was estimated at 62%, or 4 Bcf of carbon dioxide sequestered between 1984 and 1989, which would otherwise have been vented to the atmosphere. The operator estimated that in central Alberta alone, oil fields amenable to CO_2-EOR, and located within reasonable pipeline distance, have the potential to sequester 135 Bcf of CO_2.

Overall, the Viking Joffre project is reported to be an economic success. The cumulative capital and operating costs for the period 1983-1987 amounted to C$11.5 million. Net cost after revenue from oil sales was only $3 million, despite sharply lower oil prices in the latter part of the period. Approximately 53% of operating costs are attributed to purchase and injection of CO_2, 26% for well operations and maintenance, 16% for production treatment and water injection, and 5% for recycling produced gas. Cost of recycling produced CO_2 is about $0.20/Mcf.

There are numerous other depleted oil fields in Alberta with similar reservoir conditions that are expected to be amenable to CO_2-EOR. However, naturally occurring low-cost CO_2 sources in Alberta are limited, thus no significant EOR projects have been initiated in the province since the Viking Joffre field. There are nearby low-purity anthropogenic sources, such as coal-fired power plants, that could supply CO_2 to depleted oil fields in Alberta. However, supply costs would be significantly higher, estimated at almost US$50/tonne (US$2.65/Mcf; Vandenhengel and Miyagishima, 1993), which is about four times higher than operators in the U.S. Permian basin pay for CO_2 injectant.

3.6 Budafa, Nagylengyel and Szank EOR Fields, Hungary (KFV Oil & Gas)

(Magyary and Udvardi, 1991; Doleschall et al., 1992; Remenyi et al., 1995; Oil & Gas Journal, 1994/96)

Background. Many of Hungary's larger oil fields were depleted by the mid-1970s, following intensive application of primary and secondary recovery methods. CO_2-EOR projects have been conducted during the last 25 years mainly in the Budafa and Nagylengyel oil fields of western Hungary, and more recently at Szank field in south-central Hungary (**Map 3-2**). Short-lived EOR experimentation in the early 1960s with flue gas CO_2 resulted in modest success.

However, natural CO_2 discovered in a deeper reservoir underlying the Budafa oil reservoir was used increasingly in the larger scale projects active between 1971 and the mid-1990s. The Budafa reserve is 81% CO_2, with reserves of 17 billion m^3 (600 Bcf) and high reservoir pressure that did not require compression prior to underground injection within the oil fields.

Production at Budafa was from a sandstone reservoir 1,000-1,500 m deep, and from a carbonate reservoir at 2,200-2,800 m in Nagylengyel. Average reservoir porosity is relatively low at 1-2.5% in Nagylengyel and 22% in Budafa; permeabilities are high at 1,000 mD and 110 mD, respectively.

Map 3-2 here

The strategy for EOR at Szank oil field was somewhat different, with CO_2 injected at the top of the structure to create an artificial gas cap that forces residual oil out of high structural locations, via gravity segregation and drainage of attic oil. Reservoir rock at Szank field is Miocene limestone and calcareous sandstone with a porosity of 10 to 25% and permeabilities of 10 to 500 mD. The program at Szank field benefited from the experience gained from earlier CO_2 floods at the Budafa and Nagylengyel oil fields.

CO_2-EOR Performance. Given the natural reservoir pressure, temperature, and oil gravity of depleted oil fields in SW Hungary, CO_2 flooding is not miscible (although locally high pressures within the Szank reservoir are thought to achieve a sort of dynamic miscibility). In its later stages, the Nagylengyel project comprised 11 injectors and 109 producers (3,100 acres), while at Budafa there were 60 injectors and 77 producing wells (1,000 acres). The smaller Szank CO_2 flood involved only 6 injection wells and 18 producers.

The source of the injectant was CO_2-rich (81%) natural gas from the Budafa oil field. The by-product (95-98% CO_2) from gas processing plants was dehydrated and injected without the need for compression. The carbon dioxide was injected locally or piped up to 35 km for use in the Nagylengyel field. Enhanced oil production of 3,760 bbl/d and 400 bbl/d were achieved at Nagylengyel and Budafa, respectively. During a four-year period, injection of 97 million m^3 of CO_2 at Nagylengyel produced 40,400 m^3 of additional oil, for a relatively high CO_2/oil ratio of 13.4 Mcf/bbl.

3.7 Bati Raman EOR Field, Turkey (Turkish Petroleum Co.)

Background. Outside of the United States, the world's next largest commercial CO_2-EOR development is within the heavy oil carbonate reservoirs of southeast Turkey (**Table 2-2**). Close to the Iraqi border, a number of low-gravity (4° to 13° API) oil reservoirs exist in southeastern Turkey, with total OOIP estimated at 397 million m^3 (2.5 billion barrels; **Map 3-3**). Oil recovery from these reservoirs has been extremely poor, on average less than 1% of OOIP (Nakamura et al., 1995). The Turkish Petroleum Co. (TPC) tested several enhanced oil recovery processes to improve recovery of these oil resources and determined that CO_2 flooding would be most effective -- despite the low oil gravity of these fields, far too low to achieve miscibility.

Since 1986, TPC has successfully conducted CO_2 flooding of the Bati Raman field (Issever et al., 1993). This large and mature EOR project is particularly significant for estimating worldwide sequestration potential because a) it is the only large CO_2 flood located outside the United States; b) it is unique in involving a heavy oil reservoir; c) given the low gravity oil and low reservoir pressure of this shallow field, it employs immiscible CO_2 flood processes rather than the miscible EOR typical of U.S. projects; and d) the Cretaceous carbonate reservoir is broadly applicable to the Middle East oil fields that contain vast oil reserves and CO_2 sequestration potential. Unfortunately, the data availability for Bati Raman field is not as complete as for the U.S. field studies.

Map 3-3 here

Bati Raman field is the largest Turkish oil field, producing from a fractured Cretaceous carbonate reef reservoir that contains very heavy oil (9° to 15° API). Reservoir depth to the Garzan limestone is moderate at about 1,300 m (4,300 ft). The original structure is an elongated, east-west trending anticline extending 17 by 4 km, with field boundaries defined by faults and permeability pinchouts.

Primary production at Bati Raman commenced in 1961, with intensive drilling particularly during the period 1968 to 1970. Primary production was capable of achieving an estimated ultimate recovery of only about 1.5% of the estimated 294 million m^3 (1.9 BBO) of oil initially in place. A limited water injection project was implemented from 1971 to 1979 to boost oil recovery in the most depleted central portion of the field. However, water injection improved oil recovery by only several percent.

CO_2 injection was initiated in 1986, initially a small "huff-n-puff" cyclic application, which was then expanded to a 17-injector, full-flood project. Despite early breakthrough of CO_2, the injection proved to be successful in boosting oil recovery. Oil production rose to about 1,908 m^3/day (12,000 BOPD) in 1990, with no significant decline through 1997. Total CO_2 injection during this period averaged 1,700 tonnes/day (35 MMscfd). Breakthrough amounts to about 16% to 60% of injected CO_2.

Due to the high molecular weight of the crude oil at Bati Raman field, and the relatively low reservoir pressure, CO_2 does not achieve miscibility with oil within the reservoir (in contrast to the mostly miscible EOR projects of the Permian basin). Nevertheless, a large volume of CO_2 goes into solution, causing swelling of the oil which significantly reduces its viscocity. TPC estimates the solubility of CO_2 in the Bati Raman oil to be considerable (450 scf/bbl). Swelling reduces the oil's visocity from an average of 1,000 centipoise (cp) initially to less than 100 cp, facilitating flow and recovery.

Material balance calculations indicate that solution within the large in-situ oil resource is the principal mechanism for permanently sequestering CO_2 in Bati Raman and other immiscible CO_2-EOR floods. A sophisticated reservoir simulation study of the Bati Raman field estimated that intensive enhanced oil recovery at the field could recover about 6.5% of OOIP, or approximately 19 million m^3 (120 million barrels; Faure et al., 1997).

The source for the CO_2 injectant used at Bati Raman field is the Dodan natural gas field, located 89 km from Bati Raman field. The Dodan field produces gas with a natural CO_2 content of about 91%, the remainder split about equally between nitrogen and light hydrocarbons. No pre-injection processing of this gas is performed. Ultimate reserves of CO_2 at Dodan field have not been reported.

Testing conducted at a second heavy oil field in southeastern Turkey with similar reservoir conditions, the Ikiztepe field, indicates that immiscible CO_2-EOR may have wide applicability within this region (Ishii et al., 1997). The Ikiztepe test utilized CO_2 from the nearby Camarlu field, which produces gas with a natural concentration of 71% CO_2. Primary production at Ikiztepe recovered much less than 1% of the estimated 20 million m^3 (127 million barrels) of OOIP. A 5-spot test pattern, comprising a central CO_2 injection well and four surrounding oil production wells, was installed and continuous CO_2 injection took place for a 2-year period starting in 1993. Oil recovery due to immiscible CO_2 EOR was reportedly encouraging, and full development was projected to recovery about 8.6% of OOIP. The success of this second project increases the probability that CO_2-EOR may be applicable to much of the southeastern Turkey oil resources.

Table 3-5: Key Features of Bati Raman CO_2-EOR Flood, Turkey

Depth	1,300 m	4,265 feet
Oil Gravity	0.968 g/cc	12° API
Current EOR Area	NA	NA
OOIP	294 million m^3	1.85 billion barrels
Anticipated Ultimate EOR (%OOIP)	19 million m^3 (6.5%)	120 million barrels (6.5%)
Current CO_2 Injection Rate	1 million m^3/day	35 MMscfd
Anticipated Ultimate Net CO_2/EOR	NA	NA
Anticipated Ultimate CO_2 Sequestration	NA	NA

3.8 Huntsman Gas Storage Field, U.S.A. (KN Energy, Inc.)

In addition to the six case studies of CO_2-EOR projects discussed in Sections 3.1 through 3.7, it is useful to review the development and operational history of a typical underground natural gas storage (UGS) field. UGS technology is potentially applicable, with relatively small modification, to the injection, storage, and long-term monitoring of CO_2 in depleted oil and gas fields. Out of a total of approximately 500 UGS fields currently in operation in North America, Europe, and Australia, we have selected the Huntsman facility in the central United States as a representative case study.

Background. The Huntsman gas storage field is located in the central portion of the United States, southwestern Nebraska (**Map 3-4**). The Huntsman Storage Unit (HSU) comprises three individual depleted gas fields which extend over an area of about 38 km^2 (15 mi^2): the Huntsman, West Engelland, and Gurschke Fields (ARI, 1995). HSU is broadly representative of the more than one hundred gas storage fields that have been developed in depleted gas fields in this key U.S. gas transport region.

The Huntsman field was discovered in 1949 by Marathon Oil Company. During the primary production period, prior to conversion of the field to gas storage, the field had produced about 328 million m^3 (11.6 Bcf) of natural gas and 127,000 m^3 (800,000 barrels) of light oil. Most well completions have been at structurally high positions to maximize gas recovery. The field has a strong hydrologic drive, wherein water encroachment has helped to moderate pressure decline despite gas production. This hydrologic condition made the Huntsman field an attractive candidate for underground gas storage operations (although such strong water drive would be less favorable for CO_2 sequestration, because it would require high injection pressure to overcome).

Located within the Denver Basin, the Huntsman field was formed by an anticlinal structural trap, with approximately 30 m of vertical closure. The primary reservoir is the Third Dakota "J" sandstone, which averages 13.7 m (45 feet) thick and 1,470 m (4,825 feet) deep. Vertical integrity, in regards to fluid movement, is provided by the impermeable Huntsman Shale, averaging 15 m (50 feet) thick, and by the underlying Skull Creek Shale, which averages 61 m (200 feet) thick. Average reservoir parameters for the "J" sand are: porosity 22%, formation permeability, 625 millidarcies, and water saturation, 35%. A typical stratigraphic column for the field is shown in **Figure 3-3,** while a typical log response is shown in **Figure 3-4.**

In 1963 the natural gas transmission company KN Energy (Denver, Colorado, U.S.A.) purchased Huntsman field and obtained Federal Power Commission approval to convert it to an underground gas storage facility. KN re-completed 14 wells as gas storage wells and designed the field to store a maximum working gas volume of 225 million m^3 (7.9 Bcf). During the high-demand winter months, the peak gas deliverability rate is 3.0 million m^3/day (105 MMscfd)

Map 3-4

Figs 3-3 and 3-4

The Huntsman storage field wells were originally drilled and completed by Marathon during the period 1949-1951. These production wells were converted to gas storage operation in 1963 (**Figure 3-5**). The conversion process involved "killing" the wells (i.e., injecting high-density mud to overbalance the formation, thereby ceasing gas production), and then pulling and re-running 7.3-cm to 11.4-cm production tubing set above the casing perforations. The "J" sand was completed by perforating the production casing using 4 shots/foot (/30 cm) density. A permanent packer was set approximately 25 m above the "J" sand interval, isolating this zone and preventing leakage or production of fluids from overlying permeable zone.

Figure 3-6 shows a 32-year history of year-end booked volume-in-storage (VIS) for the Huntsman Storage Unit. VIS gas was built up over the period 1971 through 1975, reaching a maximum of 960 million m^3 (34 Bcf). **Figure 3-7** illustrates the reservoir pressure history of this field, showing rapid drawdown during the initial gas production period (1950-1963), followed by pressure increases related to gas injection starting in 1964. Since 1975, HSU has been operated normally, with net gas injection about balancing net withdrawals. As is typical for underground gas storage fields in the Northern Hemisphere that serve residential heating demand, gas injection reaches a maximum during the low-demand Summer months, while withdrawal peaks during the Winter (**Figure 3-8)**.

Gas Storage Performance.

As is typical for gas storage fields, as well as oil and gas production fields, a variety of open-hole and case-hole logs were run to characterize the reservoir. Open-hole logging suites included gamma ray/neutron log, resistivity electric logs, density/neutron logs, and sonic velocity logs. Cased-hole logs included casing cement bond logs, which are crucial for verifying integrity of the cement that bonds the steel casing to the formation rock, thereby precluding gas or fluid leakage.

Throughout the development stages of the Huntsman UGS field, pressure data were collected by means of well testing. Drill-stem testing (DST) was conducted to sample formation fluids, evaluate production rates, and monitor formation pressures. In addition, daily data on injection/withdrawal of gas, oil, and water volumes were collected from all wells in the field. Formation pressure was continuously monitored by means of dedicated pressure observation wells, which do not have production or withdrawal capability. KN Energy collected inflow performance curves and semi-annual bottom-hole pressure surveys in all wells. Finally, direct production logging is used, including noise surveys to sense and identify flow from the formation.

KN Energy compiles and evaluates this large operational data set using reservoir simulation. History matching of actual production and pressure data can be used to validate the reservoir model, yielding insights into reservoir properties that vary throughout the field and can never be directly measured at all places. KN Energy's reservoir model has achieved a high degree of confidence in matching actual production.

Fig 3-5

Figs 3-6 and 3-7

Fig 3-8

In conclusion, the data collection, monitoring, and analysis programs applied at the Huntsman UGS field are representative of UGS industry techniques that could apply directly to future CO_2 sequestration operations and monitoring in depleted oil and gas fields. Detailed formation logging would be necessary for characterizing injection zones and storage capacity, prior to initiating CO_2 injection. Well testing would be needed to monitor changes in formation physical properties, such as permeability and formation fluid composition, as a result of CO_2 injection and storage. Pressure monitoring wells would be needed to monitor CO_2 movements, particularly near field boundaries, and to insure secure and long-term CO_2 storage. Finally, reservoir simulation methods could be employed to history-match past CO_2 injection and storage performance, as well as to forecast refinements in future operations. UGS techniques would need to be customized for specific CO_2 sequestration applications, involving considerable technology development and field trial, but these likely would be evolutionary changes to already quite mature technology.

4.0: Methodology for Estimating Actual and Potential CO_2 Sequestration Within Enhanced Oil Recovery Projects

4.1 Introduction

Storage of carbon dioxide is already taking place on a significant scale -- indeed often at a net profit with no targeted subsidy -- within commercial enhanced oil recovery projects that utilize CO_2 flooding technology. But how much of the injected CO_2 is actually sequestered, as opposed to merely cycled through the reservoir?

It appears that much of the stored CO_2 should be considered temporary, trapped within the reservoir pore space under pressure only during the active life of the EOR (approximately 5 to 50 years). Normally, decommissioning an EOR project involves "blowing down" reservoir pressure to maximize oil recovery. Operators consider injected CO_2 to be a valuable commodity, and they may re-use it for EOR at new fields, should recycling be an economically viable option. Alternatively, if no suitable EOR candidate can be found nearby, the CO_2 produced during blow down would simply be vented to the atmosphere.

To permanently sequester injected CO_2, operators would need adequate incentives to seal CO_2 in the depleted oil field and to monitor its continued presence. Such incentives could come in the form of financial credits provided to qualifying CO_2 sequestration facilities. Nevertheless, regardless of how the field is decommissioned, a small but substantial fraction of injection CO_2 is likely to remain permanently sequestered within the reservoir, dissolved in immobile oil.

To date no individual CO_2-EOR project has been directly monitored or even indirectly assessed specifically to determine CO_2 sequestration. (Pan-Canadian's planned Weyburn field in Canada, and Norsk Hydro's proposed project at Grange field in the North Sea would be the first such overt EOR/sequestration projects.)

However, all CO_2-EOR operators maintain strict control and monitoring of CO_2 within the reservoir, for the simple reason that purchasing CO_2 is inevitably the single largest expense for an EOR project. Typically, CO_2 purchase/preparation accounts for 50% to 80% of total capital and operating costs in an EOR project. Detecting and avoiding unnecessary venting or other loss of CO_2 from the reservoir is a constant concern of EOR field engineers. Vigilant recycling and re-injection of CO_2 is generally routinely performed at mature EOR floods.

To be sure, some venting of CO_2 is inevitable at various stages in the life of an EOR project. But venting is usually restricted to the early test stages of a project or in project expansions, before installation of recycling equipment is considered to be cost-effective, or later in mature floods during overhaul of recycling facilities.

Significantly, each of the approximately 79 individual CO_2-EOR projects currently in operation relies on revenues from oil (and sometimes natural gas) sales alone, which must offset the significant cost of purchasing CO_2 for injection. No CO_2-EOR project yet receives financial benefit in the form of monetary support, CO_2 sequestration credits, or even free or reduced-cost CO_2 supplies (there are, however, investment tax credits targeting EOR development itself that indirectly promote limited sequestration). Thus, the CO_2 sequestration currently taking place in depleted oil fields is independent of any environmental intent for reduced greenhouse gas emissions. Furthermore, it is reasonable to assume that CO_2 sequestration credits or other financial incentives, once in place, could substantially increase CO_2-EOR investment and production, with larger associated sequestration.

In most cases, sequestration-related incentives would be required to justify the opportunity cost of not utilizing the CO_2 at another EOR project, in addition to the direct costs of storing, monitoring and maintaining the CO_2 within the field after the EOR project is decommissioned. These costs are discussed in Section 6.0.

4.2 CO_2 Injection, Recycling, and Sequestration Within EOR Projects

Publicly available data on CO_2 injection and cycling in depleted oil and gas fields is extremely limited. Oil and gas production regulations in the United States and many other countries require that production be reported to government oil and gas regulatory commissions regularly and in some detail. In contrast, most U.S. states (notably, Texas and New Mexico) do not require detailed records of CO_2 injected into an underground reservoir. For this study, a fragmentary picture of CO_2 injection in EOR projects had to be pieced together, based on detailed literature case studies and on information provided directly by operators. A few relatively well-documented EOR projects served as benchmarks in establishing performance “rules of thumb” for CO_2 sequestration. We then extended our analysis to the universe of other less-documented depleted oil fields.

Figure 4-1 shows a schematic cross-section of a typical EOR project, illustrating the cycling of carbon dioxide within a flooded reservoir. Actual subsurface heterogeneity and physico-chemical interactions of CO_2 within the reservoir may result in far more varied flow than illustrated here, particularly for complex reservoirs or more sophisticated injection strategies (such as WAG, foam, or other techniques). However, in general the following processes affecting enhanced oil recovery and sequestration of CO_2 are common to most reservoirs:

Fig 4-1

- **CO_2 Injection:** Carbon dioxide, purchased from an underground CO_2 reservoir (natural source) or from a natural gas processing or fertilizer manufacturing plant (anthropogenic source), is injected into the reservoir at high pressures adequate to achieve miscibility.

- **Miscibility:** Oil within the reservoir swells with the introduction of CO_2, reducing the oil's viscosity and improving its mobility.

- **Production:** Mobile oil containing dissolved CO_2 flows toward the low-pressure sink created by the production well, and is then pumped to the surface.

- **Recycling:** At the surface, carbon dioxide that has broken through is separated from the produced oil and, if economically feasible, processed using amine (DEA) treating, adsorption processes, extractive distillation techniques or membrane systems (Tannehill et al., 1994). The purified CO_2 is then recycled with purchased CO_2 down the injection wells.

- **Sequestration:** Some of the injected carbon dioxide dissolves into immobile oil resources, remaining trapped within the reservoir. Much of this CO_2 would be effectively sequestered, even after the field is decommissioned and "blown down."

- **Storage:** As long as reservoir pressure is maintained, and the producing wells are shut in, CO_2 is "sequestered" (actually stored) within the pore space of the reservoir.

- **Emissions:** Although operators first plug all known oil wells that are not in operation within the field prior to commencing CO_2 injection, some emissions are almost inevitable from unidentified and poorly abandoned wells, behind poorly cemented casing, or other pathways (including natural fractures). In addition, operators knowingly vent a small volume of CO_2, usually in early stages before recycling facilities are economically justified or during overhaul of these facilities. For this study, we conservatively (from a sequestration point of view) assumed that 10% of net CO_2 purchases are emitted; the actual percentage may be lower.

4.3 Sequestration Case Study: Rangely Weber Field

The Rangely Weber EOR project, which is operated by Chevron and located in northwestern Colorado, is one of the world's largest active CO_2 floods. It is also one of the most complete in terms of public documentation (see detailed case history in Section 3-4). The Rangely Weber project is mature and not currently undergoing major expansion, thus a steady-state analysis of CO_2 cycling can be made. Of particular analytical value, a relatively complete set of CO_2 and EOR information was obtained for current and future EOR operations at this field (**Table 4-1**). This information is sufficient to allow a first-order estimate of current and ultimate CO_2 sequestration at this field.

Chevron purchases CO_2 from Exxon's La Barge natural gas processing plant, which removes natural CO_2 contaminate from methane gas. Thus, this project may be considered to be exclusively utilizing anthropogenic carbon dioxide. In fact, Rangely Weber is believed to be currently the largest single sequestration site of anthropogenic CO_2 in the petroleum industry. (Pennzoil's SACROC project, which employed anthropogenic-sourced CO_2 for over two decades, has switched temporarily to natural CO_2 sources. By comparison, Statoil's Sleipner aquifer disposal project on the Norwegian continental shelf sequesters CO_2 at about one-quarter the rate of the Rangely Weber project.

As part of its EOR project development planning, Chevron has performed full-field reservoir simulation of the Rangely Weber unit. These simulations are based on detailed reservoir characterization and modeling that replicate the long-term underground flow of CO_2 within the reservoir and the enhanced oil recovery that can be expected. Although we do not have access to Chevron's model, they have reported certain key data, conclusions and projections that allow us to estimate CO_2 sequestration. **Figure 4-2** shows our interpretation of the current (1998) rates of CO_2 flow within the Rangely Weber sandstone reservoir, while **Figure 4-3** shows the estimated ultimate consumption of CO_2 during the full life of the project.

During 1998, Chevron injected an average total of about 4.45 million m^3/day (157 MMcfd) of CO_2 into the Rangely Weber field (Figure 4-2). Most of the injected CO_2 dissolved into mobile oil within the main sandstone reservoir, and was carried along with the oil to the production wells. About 3.28 million m^3/day (116 MMcfd) of CO_2 was separated from the field's production wells and recycled through the injectors, accounting for about three-quarters of injected CO_2. An additional 1.16 million m^3/day (41 MMcfd) of CO_2, or about one-quarter of total injected volume, was purchased and blended with the recycled volumes. Given our assumption that an average 10% of net CO_2 purchases is lost to the atmosphere due to intentional and unintentional venting (probably much too high for a mature flood such as Rangely Weber), an estimated 0.12 million m^3/day (4 MMcfd) of CO_2 is emitted.

Thus, the current rate of CO_2 sequestration at Rangely Weber field is estimated at approximately 1.05 million m^3/day (37 MMcfd). Some of this CO_2 may fill the hydrocarbon pore volume as oil is continually produced and removed from the reservoir, although the injected water more likely fills most of this new void space. Most sequestered CO_2 is probably dissolved in immobile oil that is not expected to be produced, and would probably remain in the reservoir after decommissioning.

The ultimate volume of CO_2 sequestration may also be estimated based on Chevron's simulation forecasts (**Figure 4-3**). Given Chevron's projected ratio of gross CO_2 injected to EOR production of 1.64 m^3/m (9.2 Mcf/BO), and the total EOR recovery for the project which they estimate at 21.6 million m^3 (136 MMBO), some 35.4 million m^3

Fig 4-2

Fig 4-3

(1.25 Tcf) of CO_2 are estimated to be injected over the life of the project. Furthermore, given Chevron's projected net CO_2/EOR ratio of 0.89 m^3/m (5.0 Mcf/BO), ultimate sequestration of carbon dioxide is estimated to be about 19.3 million m^3 (680 Bcf), which is equivalent to approximately 0.03 Gt of CO_2.

Thus, in its lifetime, even one of the world's very largest CO_2-EOR projects would have only an extremely limited impact on atmospheric carbon dioxide levels. CO_2 sequestration would need to be conducted on a massive scale within hundreds of depleted oil and gas fields to significantly reduce the flux of CO_2 to the atmosphere.

Table 4-1 : Carbon Dioxide Injection, Recycling, and Sequestration at Chevron's Rangely Weber Field, Colorado, U.S.A.

	Current (1998)		**Estimated Ultimate**$^{+\,\#}$		
CO_2 Volumes	MMcfd	10^6 m^3/day	Tcf	10^9 m^3	Gt
Gross CO_2 Injected	157	4.45	1.25	35.4	0.07
Recycled $CO_2$$^{@}$	116	3.28	0.57	16.1	0.03
Net CO_2 Purchases	41	1.16	0.68	19.3	0.04
Less Venting/Emissions*	4	0.12	0.07	1.90	0.00
Net CO_2 Sequestered	**37**	**5.87**	**0.61**	**17.3**	**0.03**

$^+$<u>Gross</u> based on Chevron's projected gross CO_2 injected to EOR ratio of 1,640 m^3/m^3 (9.2 Mcf/BO) and ultimate EOR reserves of 21.6 million m^3 (136 MMBO).
$^\#$ <u>Net</u> based on Chevron's projected net CO_2 injected to EOR ratio of 890 m^3/m^3 (5.0 Mcf/BO) and ultimate EOR reserves of 21.6 million m^3 (136 MMBO).
$^@$ Not forecast by Chevron; determined by subtraction.
* Not previously documented for an EOR project; assumed here to be 10% of net CO_2 purchases.
Note: numbers may not add due to rounding.

4.4 Sequestration "Rules of Thumb" Derived from EOR Projects

In addition to the Rangely Weber EOR project discussed in Section 4.3, our data base permitted a similar detailed level of analysis of CO_2 cycling and sequestration at 13 other EOR projects in the United States. We also collected substantial (but still incomplete) information on CO_2 injection from 18 additional EOR projects, not quite sufficient for estimating life-cycle sequestration for these projects. Together this data base is considered to be generally representative of average CO_2 sequestration performance at the 79 active worldwide CO_2-EOR projects, as well as the expanded universe of potential CO_2-EOR candidates in depleted oil fields.

Table 4-2 shows the estimated ultimate CO_2 purchases, EOR recovery, and calculated CO_2/EOR ratios for ten fields in the Permian basin. This data set encompasses a wide range of project size, from the largest (Altura Wasson Denver and Pennzoil SACROC) to much smaller projects with estimated ultimate EOR of less than 1.6 million m^3 (10 MMBO). The estimated ultimate enhanced oil recovery and CO_2 net purchases for these fields, which are forecasted by the operators based on past EOR performance and detailed reservoir simulation studies (just as for Rangely Weber), allowed us to compute the CO_2/EOR ratio for each project life. We then extrapolated this ratio to other comparable fields in the Permian basin. Ultimate sequestration of CO_2 at the ten Permian basin fields is estimated to total about 0.24 Gt (4.55 Tcf), with an ultimate net CO_2/EOR ratio of 1,780 m^3/m^3 (9.9 Mcf/BO).

However, this CO_2/EOR ratio is much too high for economic operation of an average EOR project, given historical oil price/cost relationships. The ratio is so high because, as discussed in Section 3-2, CO_2 usage at the Wasson Denver project turned out to be far higher than anticipated, due to extensive leakage of CO_2 out of the reservoir zone and into the overlying gas cap.

Although commendable from a sequestration point of view, we anticipate that such unusually high CO_2 usage would not take place again on a large scale in a commercial EOR project (barring sequestration incentives). Therefore, we re-calculated a 9-field CO_2/EOR average ratio of 1,040 m^3/m^3 (5.8 Mcf/BO) for the Permian basin by excluding the Wasson Denver field. Operators generally consider this lower ratio to be typical for new EOR projects in the Permian basin. It is also quite close to the 6.0 Mcf/BO ratio used by Taber (1993).

Table 4-2 : CO_2/EOR Ratios and Sequestration at Selected EOR Projects in the Permian Basin, U.S.A.

Operator	Field	Estimated Ultimate EOR (MMBO)	% of OOIP	Est. Ult. Net CO_2/EOR (Mcf/BO)	Est. Ult. Net CO_2 Purchase (Bcf)	Estimated Ultimate CO_2 Sequestration (90% of Purchased) (Bcf)	(Gt)
Altura	Wasson Denver	348	16.6%	5.3	1,860	1,674	0.09
Pennzoil	SACROC#	169	8.0%	6.0	1,014	913	0.05
Chevron	N. Ward Estes	47	15.0%	7.1	334	300	0.02
Spirit Energy	Dollarhide	28	19.0%	7.0	194	175	0.01
Phillips	Vacuum East	30	11.5%	4.3	130	117	0.01
Texaco	Vacuum	33	15.6%	3.7	122	110	0.01
Texaco	Mabee	24	5.5%	5.0	120	108	0.01
Conoco	Ford Geraldine	13	13.1%	5.0	65	59	0.00
Enron	Two Freds	8	14.1%	8.0	64	58	0.00
Fasken	Hanford	10	60.9%	5.7	57	51	0.00
Total/Average 10 Fields		**710**	**10.9%**	**5.6**	**3,960**	**3,564**	**0.19**

Anthropogenic CO_2 source was used for most of the project's life.
Note: numbers may not add due to rounding.

Table 4-3 shows CO_2 cycling and inferred sequestration at five additional fields in the Rocky Mountain and Mid-Continent regions of the United States. Rocky Mountain CO_2/EOR ratios average 870 m^3/m^3 (4.9 Mcf/BO), slightly lower than the Permian basin average. Mid-Continent fields tend to use proportionally more CO_2, at least based on our smaller data set, and are more variable, at an average 1,260 m^3/m^3 (7.1 Mcf/BO). Interestingly, all five fields in these regions for which we have data utilize anthropogenic sources for CO_2, including gas processing, fertilizer or ammonia production plants.

Table 4-3 : CO_2/EOR Ratios and Sequestration at Selected EOR Projects in the Rocky Mountain and Mid-Continent Regions, U.S.A.

Operator	Field	Estimated Ultimate EOR (MMBO)	% of OOIP	Est. Ult. Net CO_2/EOR (Mcf/BO)	Est. Ult. Net CO_2 Purchase (Bcf)	Estimated Ultimate CO_2 Sequestration (90% of Purchased) (Bcf)	(Gt)
Rocky Mountain Region							
Chevron	Rangely Weber*	136	7.2%	5.0	680	612	0.03
Amoco	Lost Soldier Tensleep*	24	9.9%	4.6	110	99	0.01
Total/Average 2 Fields		**160**	**7.6%**	**4.9**	**790**	**711**	**0.04**
Mid-Continent Region							
Henry Petr.	Sho-Vel-Tum#	10	4.8%	11.4	114	103	0.01
Stanberry Oil	Hansford@	2	16.0%	7.0	14	13	0.00
Occidental	NE Purdy#	17	7.5%	4.6	78	15	0.00
Total/Average 3 Fields		**29**	**7.2%**	**7.1**	**206**	**185**	**0.01**

Note: numbers may not add due to rounding.
* Anthropogenic CO_2 source (Exxon Labarge gas processing plant, Wyoming).
# Anthropogenic CO_2 source (Farmlands Corp. fertilizer plant in Enid, Oklahoma).
@ Anthropogenic CO_2 source (ammonia plant in Borger, Texas).

5.0: CO_2 Sequestration in Selected Worldwide Depleted Oil and Gas Fields

Compared with the United States, where extensive CO_2 enhanced oil recovery operations provide a wealth of data and understanding for analysis of sequestration, considerably less empirical information is available on the actual or potential performance of CO_2 floods in other countries. To date, commercial CO_2 floods have only been attempted outside the U.S. in Turkey, Canada, Hungary, and Trinidad, and then on a very limited scale.

However, petroleum engineers have assessed the potential for CO_2 injection and other EOR application in a number of mature petroleum provinces. Most of these studies remain confidential and proprietary, but a few (notably for the North Sea fields) have been published.

This section presents a brief (and by no means comprehensive) analysis of information from regions where CO_2 injection has been publicly addressed: including Canada, the North Sea, CIS, China, North Africa, and Southeast Asia. We have incorporated this information into our cost and sequestration model for depleted oil and gas fields, discussed in Section 6.0.

5.1 Canada

AOSTRA Study: The Alberta Oil Sands Technology and Research Authority (AOSTRA) and 24 industry partners conducted a pioneering study of the feasibility of CO_2 sequestration in certain depleted oil and gas fields in Alberta and Saskatchewan provinces (Bailey and McDonald, 1993). The AOSTRA study was sophisticated in examining the full cycle of CO_2 sequestration technology and costs -- from capture to processing to sub-surface injection – but it is their reservoir analysis of Western Canada fields that is most pertinent for the current study (Todd and Grand, 1993).

The AOSTRA study considered the major geologic settings typical of Western Canada, including both carbonate and sandstone reservoirs. Selection criteria included field size, oil density, minimum miscibility pressure, and oil production history. Miscible CO_2 flooding was the main technology evaluated, but immiscible flooding in heavy oil fields and disposal in depleted natural gas fields were also considered. Out of several hundred fields in the region, and 33 oil and 9 gas reservoirs screened, 6 depleted fields were selected for detailed study: the Carson Creek North, Pembina, Redwater, Elswick, Aberfeldy oil fields and the Carson Creek gas field. In this regard, AOSTRA did not attempt a comprehensive assessment of the sequestration potential of Western Canada, but did in fact perform a very valuable detailed evaluation of high-potential EOR targets in the region.

AOSTRA's analysis included reservoir simulation studies on each of the 5 candidate depleted oil fields (**Table 5-1**). Incremental EOR oil recovery was estimated to range from 9 to 19% of OOIP, with estimated net CO_2/EOR ratios varying widely but averaging about 540 m^3/m^3 (3 Mscf/BO) overall. This remarkably low value is only half the roughly 6 Mscf/BO ratio typical of large

U.S. EOR projects (**Table 42**). We have instead adopted the average Permian basin ratio of 6 Mcf/BO in estimating sequestration in Canada.

CO_2 disposal volumes were estimated for each field, assuming that efficiency of EOR production was the main priority in operating the project, rather than sequestration. This is a sensible working assumption, which follows least marginal cost principles in assessing the economics of CO_2 sequestration in Western Canada. We have also incorporated this assumption in developing our worldwide cost/sequestration relationship.

Table 5-1: Predicted CO_2 Sequestration in Selected Depleted Oil Fields in Western Canada (after Todd and Grand, 1993)

Field	**EOR (% OOIP)**	**EOR (10^6 m^3)**	**CO_2 Disposal (10^9 m^3)**	**Net CO_2/EOR (Mcf/BO)**
Carson Creek North	14%	8.2	4.3	2.92
Pembina	12%	31.2	10.6	1.90
Redwater	8%	13.8	19.3	7.82
Elswick	20%	0.84	0.3	1.70
Aberfeldy#	14%	13.1	1.9	0.80
Total 5 Fields	**12%**	**67.2**	**36.2**	**3.03**

Immiscible flood in heavy (13° API gravity) oil reservoir.

Economic cost/benefit analysis was performed in the AOSTRA study to examine particular scenarios, mainly the cost of sequestering 50,000 tonnes/day of CO_2 in Western Canada, which would be a significant 12% of total emissions in the province (Padamsey and Railton, 1993). For each field, the actual capital and operating costs associated with capturing, delivering, and injecting CO_2 from specific anthropogenic sources were estimated. Typical CO_2 capture costs from coal-fired power plants in Alberta were estimated at about 1992C$50/tonne, which appears very low. Pipeline delivery costs were relatively minor (C$2/tonne) due to the close proximity of the CO_2 sources to candidate oil fields. Revenues were estimated using a range of oil prices centered around 1992 actual levels (C$23/BO Edmonton Par crude).

Based on a "normal" business operating scenario, where the operator pays taxes and requires a 10% return on investment, AOSTRA estimated the Net Present Value of CO_2 sequestration in EOR projects in Western Canada that utilize anthropogenic injectant to range from -C$25.87 to -C$73.41/tonne. The average net cost was C$42.60/tonne. Furthermore, we would expect that if a typical Permian basin CO_2/EOR ratio of 6 Mcf/BO was used in the AOSTRA analysis rather than the more optimistic 3 Mcf/BO, then the net cost would be significantly higher. (For comparison, we estimated average sequestration costs in Alberta basin EOR projects to be quite comparable at an average US$31/tonne, assuming CO_2 supplies from power plant sources - Appendix 1B).

For the Carson Creek natural gas field, the single depleted gas field studied by AOSTRA, the total CO_2 sequestration cost was estimated at US$53 to $73/tonne. Using the average AOSTRA values, an estimated 278 million tonnes of CO_2 could be sequestered in Western Canada at a staggering net cost of approximately C$11.8 billion (1992 dollars).

However, if delivered CO_2 supply costs to these projects were as low as they are in the U.S. Permian basin -- only about C$8.00/tonne from natural CO_2 sources -- then many of the EOR projects evaluated in Western Canada would be economically viable. Obviously, CO_2 sequestration using anthropogenic sources will not take place in depleted Western Canadian without significant financial incentives or regulatory restrictions on emissions.

The AOSTRA study also addressed for the first time several important philosophical questions regarding possible conflicts between efficient EOR production and maximizing CO_2 sequestration (Todd and Grand, 1993). We further discuss these issues in Section 7.0.

5.2 North Sea

The North Sea is a major petroleum province currently producing about 1.3 million m^3/day (8 million b/d), slightly more than U.S. oil production. As an offshore region, there are important timing implications for adopting CO_2 flooding in the North Sea fields. An offshore EOR project should be phased in as conventional production declines, to avoid excessive increase in operational costs. Once North Sea (or other offshore) oil platforms are decommissioned and removed, it is very unlikely that a CO_2 EOR/sequestration project could justify the costs of a new platform and new wells. This means that large offshore EOR/sequestration projects should start within a "window of opportunity" that will exist during the next 5 to 10 years.

Many North Sea reservoirs are produced using secondary waterflooding techniques. Pilot tertiary gas or Water-Alternate-Gas (WAG) injection techniques have been implemented in several North Sea fields, but are not yet widespread. Although to some extent reservoir heterogeneity and other factors reduce oil recovery efficiency, on the whole the North Sea reservoirs are amenable to enhanced oil recovery methods.

Norway. Most of the oil in place on the Norwegian continental shelf is light oil and occurs in relatively permeable reservoirs. Hence, primary and secondary (waterflood) oil recovery is already quite high at an expected ultimate 40% of OOIP (**Table 5-2**). A 1996 internal Statoil study estimated that advanced recovery methods on the Norwegian continental shelf could be expected to recover an additional 500 million m^3 (3.1 BBO), of which only about 10% was projected to be from gas injection methods, including CO_2-EOR (Krakstad et al., 1997).

An earlier joint industry/government study assessed the EOR potential of 15 major offshore Norwegian fields, ranking the application of CO_2 or flue gas injection as the least viable option for tertiary oil recovery, after surfactant flooding, WAG, polymer flooding, and thermal methods (Hinderaker et al., 1991). Recovery using hydrocarbon flooding is expected to vary with reservoir conditions, from 3 to 7% of OOIP in 10 favorable reservoirs to less than 3% of OOIP in ten other reservoirs with unfavorable permeability profiles.

Industry planning for enhanced oil recovery in the North Sea oil fields generally assumes that re-injection of natural gas will be the primary EOR method. Indeed, during the 1990's, WAG injection has been increasingly applied to oil reservoirs in the North Sea. This is because many of the fields that are not yet linked to market by natural gas pipeline are experiencing an increasing volume of associated natural gas production along with oil. Furthermore, CO_2 supplies are considered to be relatively distant and costly. Natural gas at North Sea fields generally contains natural CO_2 concentrations of about 1%, too small for enrichment.

The following examples show the type of EOR activity currently taking place in the North Sea oil fields:

- Saga Petroleum is conducting pilot-scale gas re-injection EOR at the giant Snorre field on the Norwegian continental shelf, one of the major oil fields in the North Sea with OOIP estimated at 200 million m^3 (1.3 BBO) (Svorstol et al., 1997).

- Norsk Hydro initiated an immiscible WAG injection involving six injectors at Brage Field in 1994. Material balance indicates that about half of the injected gas remains stored in the reservoir. The EOR project is expected to recover at least an additional 3% of the 129 million m^3 (0.81 BBO) OOIP (Skauge and Berg, 1997).

- Norsk Hydro's Troll oil and gas field, expected to recover 25% of the 680 million m^3 (4.3 BBO) OOIP, is connected to a natural gas pipeline and thus gas re-injection is not necessarily the only EOR option under consideration (Wennemo et al., 1997).

- Norsk Hydro is reportedly investigating the use of process CO_2 for a huge US$2 billion EOR project at its offshore Grane field in Block 25/11 (Oil and Gas Journal, 1998). Grane field produces heavy (19° API gravity) oil from sandstone reservoirs at depth of 1,700 m. Norsk Hydro estimates that immiscible EOR could recover 80 to 120 million m^3 (500 to 750 MMBO) of incremental oil. CO_2 and hydrogen would be generated from natural gas feedstock using a steam reforming process. The CO_2 would then be injected for EOR, with the hydrogen fueling onshore electric power generation. Given the huge size of this project (four times larger than SACROC, currently the largest CO_2-EOR project), its offshore location (unprecedented for CO_2-EOR), and its relatively costly CO_2 supply source, successful implementation would be a remarkable achievement.

Table 5-2: Oil fields on the Norwegian Continental Shelf

Field	Original Oil In Place		Percent	EOR
	Million m^3	Billion Bbl	Recovery#	Projects
Statfjord (all)	1,035	6.51	47%	
Troll	680	4.28	25%	To be determined

Gullfaks	561	3.53	41%	WAG pilot
Oseberg	460	2.89	60%	Gas injection
Snorre	341	2.14	31%	WAG pilot
Heidrun	335	2.11	26%	
Draugen	155	0.97	44%	
Ula	131	0.82	51%	
Brage	129	0.81	36%	Immiscible WAG
Veslefrikk	92	0.58	39%	
Other	264	1.66	36%	
Total	**4,183**	**26.31**	**40%**	

Primary and secondary recovery only.
Sources: Hinderaker et al., 1991; Skauge et al., 1997; Skauge and Berg, 1997; Wennemo et al., 1997; Stenmark and Andfossen, 1995.

United Kingdom.

- BP's Wytch Farm field, located in onshore southern England, was approved in 1997 for a miscible natural gas injection EOR project, which is planned to cover half of the field within 10 years (Harrison et al., 1997). The Wytch Farm EOR project is forecast to recovery an additional 7.5% within the flooded portion of the 120 million m^3 (750 MMBO) OOIP, beyond the current anticipated 50% recovery factor, with a favorable 1.7 Mcf/BO gas/oil ratio.

5.3 Russia/CIS

Enhanced oil recovery projects in Russia employ thermal, hydrocarbon gas, or polymer flooding. Carbon dioxide EOR has not been extensively tested. Most active EOR reserves are located in West Siberia (36% of total CIS EOR), with substantial development also in the Volga-Urals (23%) and Kazakhstan (27%). West Siberia EOR is mainly gas and chemical flooding, while chemical EOR predominates in the Volga-Urals and thermal EOR in Kazakhstan (Jacquard, 1991).

5.4 North Africa

The Bu Attifel field is a giant oil reservoir located in the Sirte Basin of the Libyan desert, about 400 km southeast of Benghazi. Discovered in 1967, and first developed in 1972, the field produces light (41° API) gravity oil with a high wax content (37%) from sandstone reservoir at a depth of about 4,500 m. Oil production has averaged over 20,000 m^3/day (125 MBOD) during the period 1972 to 1997. Oil recovery under primary and secondary (waterflood) production is expected to reach 50% of the 620 Mm^3 (3.9 BBO) OOIP.

AGIP, the Italian oil company that operates the field, is conducting an evaluation of the potential for EOR at the field (Causin et al., 1997). Laboratory experiments on Bu Attifel oil under simulated reservoir conditions showed that CO_2 miscibility could be achieved, but with the possible side effects of corrosion and paraffin precipitation. In the end, however, AGIP concluded that injection of natural gas enriched with LPG would give better enhanced recovery performance at this field, with no deleterious side effects.

5.5 China

The primary enhanced oil recovery methods employed in China are polymer and thermal flood techniques, probably because large low-cost carbon dioxide supplies have not yet been identified (Han et al., 1997). Carbon dioxide flooding has not been widely tested and there are no commercial CO_2-EOR projects. During the period 1985 to 1995, China's Ministry of Petroleum Industry (MOPI) conducted a technical evaluation of the country's oil fields to identify candidates for CO_2 enhanced oil recovery (Liu et al., 1998). MOPI concluded that miscible EOR using CO_2 could be technically feasible in numerous depleted oil fields throughout China, including Zhongyuan, Jianghan, Kelamayi, Liaohe, Jilin, Jiangsu, Dagang, Yumen and other oil fields. Remaining oil in place within all depleted oil field candidates was estimated at about 639 million tonnes (3.8 BBO), with total enhanced recovery potential estimated at about 86 million tonnes (500 MMBO).

Actual CO_2-EOR testing experience in China is limited. A 4-injector, 21-producer CO_2 injection pilot is planned for Jilin oil field in northeast China. However, no commercial, large-scale CO_2-EOR flood is yet underway. We relied on the MOPI assessment of readily accessible CO_2-EOR resources in estimating China's CO_2 sequestration potential in EOR projects. We used the Oil & Gas Journal field data base for evaluating potential sequestration in non-EOR depleted oil and gas fields. Finally, we used the USGS resource assessment of China in evaluating sequestration in undiscovered oil and gas fields.

5.6 Southeast Asia

Malaysia. Petronas, the national oil company of Malaysia, has conducted internal studies of the potential for enhanced oil recovery in Malaysian oil fields using carbon dioxide flooding (Anwar Raja and Calin, 1982). Although the resource potential information remains confidential, more recent laboratory work indicates that oil from Dulang field (API gravity 38°) and Semangkok field (API gravity 39°), which are considered representative of the "waxy" crudes found in peninsular Malaysia, could be miscible with CO_2 under typical reservoir temperature and pressure conditions (Anwar Raja et al., 1997).

Indonesia. Second only to the U.S. in enhanced oil recovery, Indonesia currently produces about 50,000 m^3/day (300,000 BOPD) of EOR. However, to date essentially all EOR projects in Indonesia have employed thermal EOR methods. Primary and secondary production from oil reservoirs in Indonesia generally achieve recovery of 20 to 45% of OOIP. Oil and reservoir properties in many depleted fields are appropriate for CO_2 flooding (Cockcroft et al., 1988).

A number of depleted petroleum fields exist in Indonesia within the following onshore basins: the North, Central and South Sumatra basins; Northwest and East Java basins; Kutei, Tarakan, and

Barito basins in Kalimantan; and Salawati basin in Irian Jaya. Offshore basins also exist, but these are less mature and higher cost for CO_2 sequestration and are not described here in detail.

North Sumatra basin has been producing for over 100 years, with total production of over 80 million m^3 (500 MMBO). Most fields produce very light oil (50° API gravity) from shallow sandstone reservoirs at depths of 400 to 1,200 m. The Rantau and Tualang fields have been successfully waterflooded, which indicates that CO_2 floods may be effective. However, considering the shallow, light-oil reservoir these conditions, CO_2-EOR would most likely be immiscible and thus less efficient.

Large quantities of carbon dioxide are present within all Sumatra and most Java basins, mostly sourced from the volcanic arc. Significant anthropogenic CO_2 streams are generated by gas processing plants; these could supply CO_2 injectant at relatively low cost. The largest, Mobil's LNG processing plant at Arun field along the North Sumatra coast processes a 15 mol % gas stream to generate approximately 10 million m^3/day (350 MMcfd) of pure CO_2 (Musamma, 1994).

Central Sumatra basin currently is Indonesia's most productive oil basin, with over 60 fields in production. The Duri field steamflood, operated by Caltex Pacific Indonesia, is by far the world's largest EOR project, producing 50,000 m^3/day (300,000 BOPD) of heavy (22° API gravity) oil from highly porous and permeable sandstone reservoirs. CO_2 flooding would not be appropriate at Duri, given the low gravity oil and, particularly, the low reservoir pressure of this shallow (300 m) reservoir. However, other lighter gravity (40° API) and deeper (>1,800 m) fields exist in Central Sumatra that could be attractive targets for CO_2 floods. Small undeveloped natural CO_2 deposits exist within the Barisan Mountain belt in onshore Central Sumatra.

Offshore, the planned Exxon/Mobil/Pertamina East Natuna gas project in the South China Sea is the largest gas field complex in Asia. East Natuna has enormous gas reserves (6.3 Gm^3 or 222 Tcf), of which about 71% by volume is CO_2. Current plans for this US$40 billion development envision re-injection of separated CO_2 into shallow offshore aquifers (Oil & Gas Journal, 1999). However, a pipeline could conceivably be constructed to transport large volumes of pure gas plant (anthropogenic) CO_2 to depleted oil fields in Sumatra for EOR. At peak production, about 28×10^9 m^3 (1 Bcfd) of pure CO_2 production is anticipated.

South Sumatra/Jambi basin is the most thoroughly explored basin in Indonesia, and has the largest number of oil and gas fields. Waterfloods have been succesfully implemented at Tanjung Tiga, Jene, Pian, Pendopo, Kampong Minyak and other fields. Fluid (30-50° API gravity) and reservoir (depth 600 to 1,800 m) characteristics are more amenable to miscible (or, occasionally, immiscible) CO_2 flooding compared with Central Sumatra. In addition, CO_2 is abundant in South Sumatra. However, depleted fields in South Sumatra are generally more heavily faulted and compartmentalized, which could hinder reservoir continuity and sweep efficiency.

Gulf Indonesia's 10-Tcf Corridor Block natural gas fields, recently brought onstream in Fall 1998, produces 32% CO_2 by volume. Most of this CO_2 must be stripped out to meet pipeline specifications. By 2001, gas processing is expected to generate about 7 million m^3/day (200 MMcfd) of pure waste CO_2 from the Corridor fields, constituting a potential anthropogenic source for injection and sequestration in depleted South Sumatra fields.

Java has smaller petroleum fields compared with Sumatra. The largest is Pertamina's Jatibarang field in the West Java basin, which produces waxy 30° API gravity crude from fractured igneous reservoirs at a depth of 2,500 m. Earlier this century, the East Java basin produced over 25 million m^3 (150 MMBO) of oil from some 30 sandstone reservoirs, but today this region is highly depleted with only minor production. Most fields are 1,000 to 1,600 m deep with light crude, and should be amenable for miscible CO_2 flooding.

Kutei basin in east Kalimantan (island of Borneo) is Indonesia's second most productive petroleum province after Central Sumatra. Oil fields here generally contain light (40° API) crude, mostly at depths of 600 to 2,000 m and should be appropriate for miscible CO_2 flooding. However, some potential reservoir challenges facing EOR development include large primary gas caps (which could become contaminated), and multiple stratigraphically dispersed sands of varying thickness that require costly multiple well completions. Neither natural nor anthropogenic CO_2 is particularly abundant in any of the lightly populated Kalimantan basins.

Tarakan basin in northeast Kalimantan includes the large Pamusian, Bunyu, and Sembakung oil fields. Pamusian field produces low-gravity (18° API) crude from multiple sandstone reservoirs. Waterfloods have recently been introduced but little has been published on their performance.

Barito basin in southeast Kalimantan has not been a prolific petroleum production area.

Salawati basin in Irian Jaya (adjacent to New Guinea) is located in remote eastern Indonesia. Oil gravity is light (30 to 50° API) and the carbonate reservoir depth is mostly deeper than 800 m, including 30% deeper than 2,000 m, thus miscible CO_2 flooding should be feasible. However, availability of CO_2 injectant will be a major challenge for this extremely remote area.

5.7 South America

As part of a national review of the potential for CO_2-EOR in Venezuelan oil fields, PDVSA, the Venezuelan national oil company, screened and ranked over 600 reservoirs throughout the country during the early 1990's. One field, with favorable reservoir attributes and CO_2 supply, was selected for detailed reservoir simulation analysis. PDVSA conducted a feasibility study for CO_2 flooding of the Nipa 100 field, located in eastern Venezuela (Almeida, et al., 1993). Nipa's location close to a CO_2 source was an important reason for its selection for detailed study. The CO_2 flood planned for Nipa, if implemented, would be the first non-thermal EOR project in Venezuela.

The NIP-103 reservoir of Nipa field was mostly developed in 1958. Reservoir depth is about 2,560 m (8,400 ft). The original reservoir pressure of 3,420 psia is favorably above the experimentally determined minimum miscibility pressure of about 3,000 psia. The high mobility ratio of about 12, while less than the 20 to 40 typical West Texas floods, suggests that WAG methods would be required to control viscous fingering of injected CO_2. Furthermore, the relatively high CO_2/oil density contrast of 16.5 suggests that injected CO_2 would override the oil column.

Cumulative production through December 1990 was a relatively small 430,000 m^3 (2.7 MMBO) of oil, 90,000 m^3 (0.564 MMB) of water, and 130,000 m^3 (4.6 MMscf) of gas. Incremental EOR under the optimal WAG ratio (1:2) was modeled to be approximately 12% of OOIP, with a favorably low net CO_2 utilization of about 4 Mscf/BO with recycling. It is worth noting, however, that the Nipa field was considered to be one of the most favorable reservoirs for CO_2-EOR in Venezuela, and average net CO_2/oil ratios within this province are likely to be considerably higher.

The carbon dioxide source targeted for the Nipa field was waste stream from a cryogenic gas processing plant at San Joaquin, which treats natural gas containing 5-6% CO_2. If separated from the natural gas stream, approximately 1.3 million m^3 (45 MMscfd) of CO_2 could be supplied to the field for injectant.

6.0: Economic Model of CO_2 Sequestration in Depleted Oil and Natural Gas Fields

This section discusses the methodology used in constructing a data base and economic model for estimating the worldwide CO_2 sequestration potential in depleted oil and natural gas fields. This model was then used to generate sequestration/cost curves that help define the broad economics of CO_2 sequestration in depleted petroleum fields. The model can be readily improved and updated as new cost or resource data become available, or as sequestration technology advances.

Our petroleum resource data base is centered around information from the world's 155 largest individual geologic petroleum provinces. We used basin categories defined by the U.S. Geological Survey (USGS), as part of their ongoing global assessment of oil and gas resources (Klett et al., 1997; Masters et al., 1998). The USGS grouped approximately 32,000 known oil and gas fields throughout the world and allocated them to several hundred individual petroleum provinces. They also assessed the worldwide potential for additional recoverable petroleum resources that are likely to be discovered and developed over the next few centuries.

The USGS studies represent the first global assessments of petroleum resources that were performed using a unified methodology. They provide a convenient yet sufficiently detailed level of analysis for our sequestration study. During the next several years, the USGS plans to release more detailed analysis on important petroleum provinces, thus our model can be readily updated and improved by integrating new data as it becomes available. For some specific provinces, we have augmented or modified the USGS data using more detailed published information.

As shown in **Appendix 1**, the CO_2 sequestration model comprises two separate components (or submodules): 1) Sequestration in depleted oil fields, including enhanced oil recovery (Appendix 1B); and 2) Sequestration in depleted natural gas fields (Appendix 1C). The key assumptions and methodology used in developing the model are discussed in the following sections.

6.1 Enhanced Oil Recovery Submodule

The Enhanced Oil Recovery (EOR) Submodule screens the worldwide petroleum resource data base to estimate the volume and costs of EOR development and associated CO_2 sequestration. The principal assumptions and data used in this submodule are summarized as follows:

1. Cumulative Production & Reserves: Data for the cumulative volume of oil, natural gas, and natural gas liquids produced, plus remaining proved reserves were adopted from Klett et al., 1997. Data are current through 1992 for the United States, 1993 for Canada, and 2nd Quarter 1996 for the rest of the world. Petroleum provinces that have been in production for many decades often had inadequate records during the early, high-rate period of exploitation. For these regions, the recorded cumulative production & reserves value may underestimate actual sequestration potential. Cumulative production & reserves in worldwide oil and gas fields totaled approximately 2,845 billion barrels of oil equivalent (BBOE), calculated on an energy-equivalent basis (assuming 1 barrel is the thermal equivalent of 6,000 ft^3 of natural gas). Our model specifically addresses the largest 155 petroleum provinces, which account for 98.6% of total worldwide cumulative production and reserves (Appendix 1A).

2. Undiscovered Resources: Proved petroleum reserves are by definition highly conservative measurements of actual productive potential. Even in mature provinces such as the U.S., reserves nearly always underestimate the amount of petroleum that will eventually be found and produced. For example, the oil reserve/production ratio in the U.S. has remained well below 10 years for the past several decades, yet oil reserves have not been exhausted. In fact, oil will continue to be produced in the U.S. for many more decades as new, undiscovered or inferred resources are developed and thereby converted into proved reserves. In evaluating the worldwide CO_2 sequestration potential, it is not sufficient to include only cumulative production and remaining proved reserves. Undiscovered resources, which are statistically likely to be found and developed over the next few centuries -- just as they have contributed continuously to proved reserves over the past century -- also must be considered. The North Sea petroleum province is an excellent recent example of an undiscovered resource partially converted into proved reserves.

Typically, ultimate petroleum reserves will eventually grow to 2 to 7 times the initial level of booked proved reserves, following a normal pattern of discovery and development. Improved extraction technologies (such as horizontal drilling or hydraulic stimulation) add additional reserves. For our model, we used the USGS estimate of potentially recoverable, undiscovered petroleum resources (Masters et al., 1998). It should be noted that these values assume current levels of petroleum extraction technology; advanced technologies currently under development but not yet in application would add additional resource potential to the USGS undiscovered resource value. The 155 largest provinces that were specifically modeled account for about 80.5% of the global total undiscovered petroleum resource base, estimated at 1,301 BBOE (Appendix 1A).

3. Ultimate Recoverable. Sum of 1 and 2, ranked by energy value in units of barrel of oil energy equivalents (BOEE). The 155 modeled provinces account for about 92.9% of the total worldwide ultimate recoverable petroleum, which is estimated at 4,147 BBOE (Appendix 1A).

4. Reservoir Province. The name and rank (separate rankings according to ultimate BOEE and to CO_2 sequestration potential) (Appendix 1B).

5. Reservoir Attributes. Average or typical depth and oil gravity, which are the two key reservoir properties that most affect applicability of CO_2 EOR. Surface characteristics, such as location (onshore or offshore or both) and approximate distance to large current anthropogenic CO_2 supplies, also have a profound impact on costs. However, it should be noted that many of the petroleum provinces (e.g., Western Siberia or Mesopotamia) are enormous systems comprising many basins and individual formations. There is likely to be considerable diversity within these large systems in terms of reservoir attributes. The depth and oil gravity data were not available from the USGS data set, and were instead adapted from the Oil & Gas Journal Worldwide Production report (1998) (Appendix 1B).

6. Miscibility. Based on average oil gravity and reservoir depth, discussed above, an estimate of the percentage of overall oil resources that would be amenable to miscible or immiscible flooding was made. Even though most petroleum provinces were found to have suitable average depth and oil gravity, we used a cap of 75% of the resource for both miscible and immiscible flooding. This is because the average masks wide variability in these characteristics, and also because other as yet unidentified geologic factors are likely to negatively impact EOR operations at some fields. (As a conservative measure, we did not include any additional sequestration capacity that may exist in reservoirs where the original oil reserve was less than that required to fill up the reservoir to the "spill point.") Screening criteria outlined in Taber 1993 were used (Appendix 1B).

7. Estimated EOR Costs. Four individual cost categories were defined. Data provided by Shell CO_2 Co. on the typical EOR costs of new CO_2 floods in the Permian basin were used as a basis (Schoeling, 1998). These costs (admittedly for one of the world's lowest-cost settings) were then adjusted by factors to account for potentially higher cost settings, such as offshore, deeper, or more remote EOR projects. The four cost components are: field well capital costs; pipeline capital costs; operations & maintenance costs; and CO_2 supply costs.

Field well capital costs include drilling, completion, equipping, gathering, and (if offshore) platform costs. CO_2 pipeline capital costs are estimated for three settings: near (0 to 10 km), moderate (10 to 100 km), and far (100 to 500 km). Operations and maintenance (O&M) costs were estimated based on depth range (800-1,500 m; 1,500-2,500 m; >2,500 m), and include the relatively small costs of monitoring to ensure long-term sequestration. Offshore factors ranging from 1.5 to 3.0 were applied to the onshore costs, reflecting the typically much higher offshore capital and operating costs.

CO_2 supply costs (delivered, high purity and pressurized to approximately 1,000 psi) represent the single largest individual cost component for a sequestration system. Several types of supply were run as sensitivities, including natural sources ($0.65/Mcf or about $12/t); captured waste CO_2 from natural gas processing plants ($1.00/Mcf or about $18/t); and captured CO_2 from power generation plant flue gas ($3.00/Mcf or about $53/t). In addition, an advanced power plant CO_2 capture technology case was run, on the assumption that future R&D into this relatively immature area will reduce supply costs to about $2.00/Mcf or $36/t (Appendix 1B).

8. Profitability. Estimated EOR costs were compared with typical sales revenues from enhanced oil recovery to determine an overall average cost or profitability for each province. This permitted a cost/sequestration supply curve to be developed. We assumed a $15/BO world oil price, less 20% for government taxes, for a typical net wellhead of $12/BO worldwide. Actual oil price was adjusted for average gravity within each petroleum province, using a typical market adjustment of $0.10/BO per degree of API gravity. Obviously, the price of oil has a powerful impact on EOR profitability. Higher oil prices would dramatically reduce net sequestration costs (Appendix 1B).

9. EOR. Although cumulative production and reserves are well defined in most petroleum provinces, the target original oil in place (OOIP) has not yet been defined. We estimated OOIP from ultimate recovery and from oil gravity, according to the following relationship:

OOIP = Ultimate Recoverable Resources / ((Average API Gravity + 5)/100)

For example, we estimate that primary and secondary recovery operations at a reservoir with average 40° API gravity crude would be expected to recover about 45% of OOIP, whereas a reservoir containing 20° API crude would recovery only about 25% of OOIP.

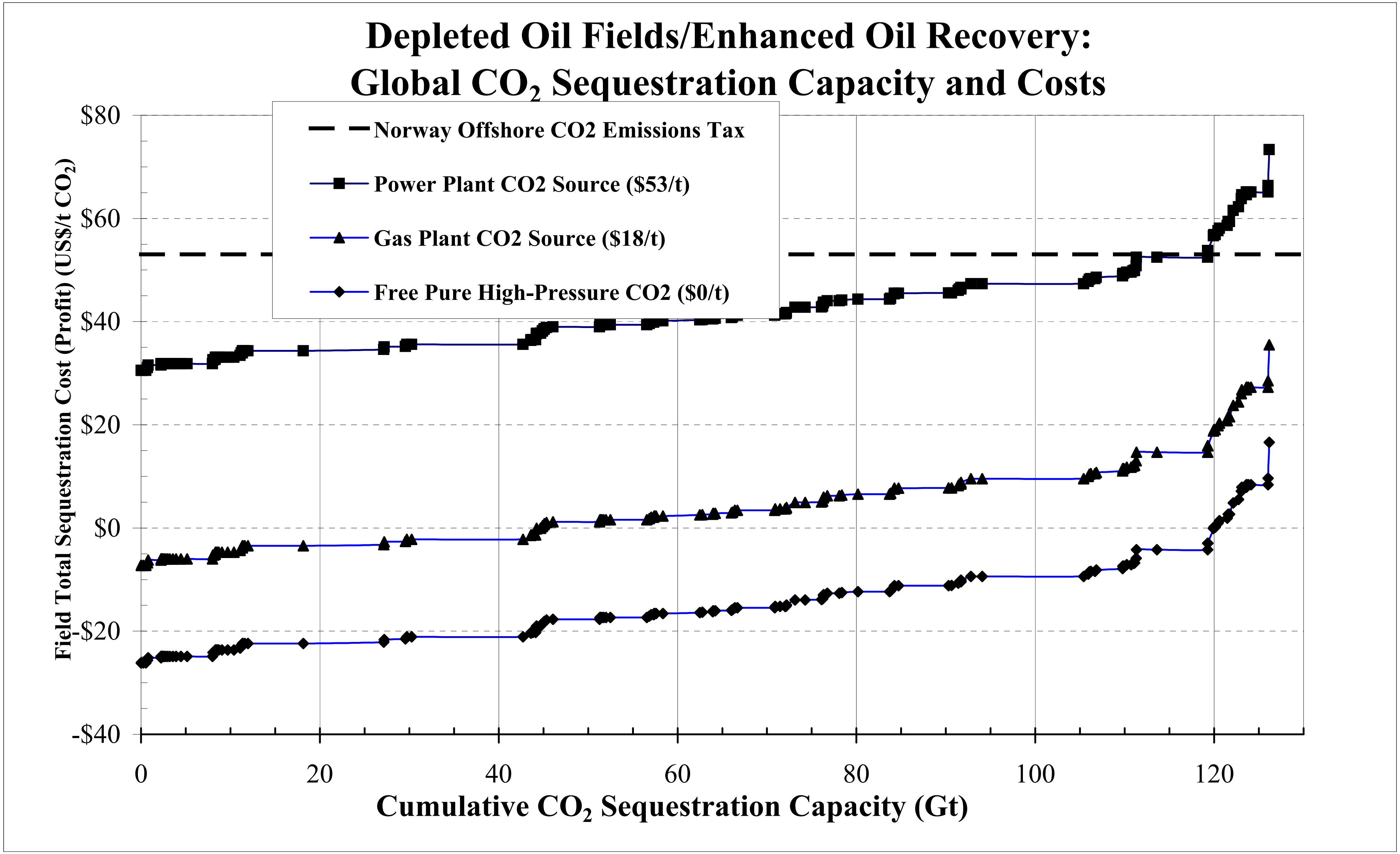
The average Permian basin EOR project is expected to recover about 10.9% of OOIP (**Table 4-2**). We used an empirical relationship between oil gravity and EOR recovery determined for 7 Permian basin EOR projects, wherein recovery ranges from about 20% of OOIP for oil gravity above 42° API to a minimum of 5% of OOIP for oil heavier than about 31° API gravity **(Figure 6-1).**

Overall, our average value of about 8% of OOIP compared closely with the 22% of cumulative production plus reserves used by Taber 1993, if one assumes that primary + secondary recovery yields 33% of OOIP (i.e., 8%/33% is nearly equal to 22%). Other factors, such as the reservoir drive mechanism, also affect recovery of OOIP (Van der Meer and van der Straaten, 1993). However, oil gravity was selected as the most readily simulated variable given the limited budget of our modeling effort (Appendix 1B).

10. CO_2 Sequestration Potential. The average net CO_2 purchased/EOR ratio in Permian basin EOR projects is about 5.8 Mcf/BO (Table 4-2). Assuming that about 5% of CO_2 purchased is lost to the atmosphere during recycling and from insecure wellbore leakage, we assumed a worldwide average net ratio of 6.0 Mcf/BO. This is the same ratio used by Taber 1993. We further estimated that immiscible EOR resources would require a higher 10 Mcf/BO ratio, based on a study of Hansford Marmaton field (Brock and Bryan, 1987). Sequestration volumes and costs were then converted into metric units of gigatonnes (Gt) and U.S. dollars per metric tonne ($/t). The 155 individual estimates were then sorted, cumulated, and graphed in **Figure 6-2.** (Appendix 1B).

Figs 6-1 and 6-3 (sic)

Fig 6-2



Depleted Oil Fields/Enhanced Oil Recovery:
Global CO_2 Sequestration Capacity and Costs
Norway Offshore CO2 Emissions Tax
Power Plant CO2 Source ($53/t)
Gas Plant CO2 Source ($18/t)
Free Pure High-Pressure CO2 ($0/t)
Field Total Sequestration Cost (Profit) (US$/t CO_2)
$80
$60
$40
$20
$0
-$20
-$40
0
20
40
60
80
100
120
Cumulative CO_2 Sequestration Capacity (Gt)

6.2 Depleted Natural Gas Field Submodule

Cumulative Production & Reserves: Same as 6.1.
Undiscovered Resources: Same as 6.1.
Ultimate Recoverable. Same as 6.1.
Reservoir Province. Same as 6.1.

2. Reservoir Attributes. The analyses of the location of the depleted gas field (onshore vs. offshore) and the distance to anthropogenic CO_2 supply are the same as for depleted oil fields. Reservoir depth is assumed to control pressure and temperature by typical gradients of 0.433 psi/foot and 1.5° F/100 feet. The gas gravity of CH_4 is assumed to be 0.6 (Appendix 1C).

3. Estimated CO_2 Injection Costs. Four individual cost categories were defined. Most of the Shell CO_2 Co. costs used above for assessing EOR economics were not appropriate, thus other sources were used. Drilling, completing, equipping, and operating costs for injection wells in the United States were based on data series published annually by the Joint Association Survey (American Petroleum Institute, 1998) and the U.S. Department of Energy (1998). We assumed that half of the wells used for CO_2 sequestration in depleted natural gas fields would be converted producing wells (at small conversion cost), and that half would be newly drilled. We further assumed that the costs of CO_2 injectant include dehydration, allowing use of fiberglass or conventional carbon steel tubulars. Drilling costs for a 1500-m deep natural gas well in the United States averaged about $600,000 during 1997. Completion and equipment costs added an additional $125,000.

Estimated ultimate net CO_2 injected per injector well varies widely in the Permian basin, from about 0.5 Bcf to over 7 Bcf. The Chevron Rangely Weber case study is expected to average 1.8 Bcf/injection well. We assumed a discounted (10% annual) 57 million m^3 (2.0 Bcf) of total CO_2 injection per injection well to allow costs to be expressed on a per-Mcf basis. Well operating and maintenance (O&M) costs for CO_2 injection are based on the average U.S. costs of $50,000/year and a 20-year injection life, but we halved these operating costs because they are for production wells (which includes lifting costs) rather than for injection wells (no lifting costs). Pipeline capital costs were from the Shell CO_2 data, converted to $/Mcf using the standard 6 Mcf/BO ratio. The same offshore factors were used as in the EOR analysis.

Just as for the EOR analysis, CO_2 supply costs to depleted natural gas fields (delivered, high purity and pressurized) were run as sensitivities. We examined natural sources ($0.65/Mcf or about $12/t); captured waste CO_2 from natural gas processing plants ($1.00/Mcf Mcf or about $18/t); and captured CO_2 from power generation plant flue gas ($3.00/Mcf or about $53/t) (Appendix 1C). We also examined the potential for advanced power plant CO_2 capture technology, using CO_2 supply costs of $2.00/Mcf ($36/t).

4. Profitability. There is no direct economic benefit from CO_2 disposal in depleted natural gas fields that can offset costs, thus all costs are net costs (Appendix 1C).

5. CO_2 Volume. In estimating the sequestration potential of depleted natural gas fields, the reservoir drive mechanism should be considered. Assuming the void created by natural gas production would be available is a better assumption for a depletion drive gas reservoir than a water drive or partial water drive reservoir. Displacing an advanced aquifer would require significant injection pressure and consequently high cost of operation. Hence depletion drive reservoirs would be preferred. However, for this study depletion drive was assumed for all petroleum provinces due to budgetary constraints.

The compressibility of carbon dioxide under typical reservoir pressures is significantly greater than that of natural gas. This means that a given void space within the reservoir can store a much larger volume of CO_2 (measured at standard pressure and temperature conditions) than methane. And because a mole of CO_2 weighs much more than a mole of CH_4, the mass of CO_2 that can be stored is far greater than the mass of the natural gas produced from the reservoir.

Like the van der Meer and van der Straaten (1993) study, we assumed that CO_2 could be injected to fill a certain percentage of the void space in depleted gas fields that is created when the natural gas is produced. However, this earlier study made the simplifying assumption, reasonable given the study's scope of analysis, that the mass of CO_2 stored in a given reservoir volume would not vary with depth. In fact, CO_2 compressibility varies widely relative to that of methane over the range of depth/pressure/temperature conditions likely to be encountered in depleted natural gas reservoirs. Generally, a significantly greater standard volume of CO_2 can occupy the void space within the reservoir compared with CH_4, but this ratio varies from under 1.5 to over 3 times.

Using standard petroleum engineering methodology, we computed the actual variation of the volumetric ratio of CO_2/CH_4 that would be anticipated within each of the USGS depleted natural gas provinces **(Figure 6-3**). This relationship was calculated using the ideal gas law, actual compressibility factors ($z = PV/RT$) for CO_2 and CH_4, and typical depth/pressure (0.433 psi/foot) and depth/temperature (1.5° F/100 feet) gradients. Our analysis shows that a typical depleted gas reservoir can hold more than 3 times the standard volume of CO_2 at a depth of 1000 m compared with the standard volume of CH_4, but this ratio declines to less than 1.5 times at depths of over 3,000 m.

Table 6-1 illustrates the methodology and assumptions used for calculating CO_2/CH_4 volumetric ratios, for representative depth values. The ratio was then used in Appendix 1C, item number 5, for calculating potential CO_2 sequestration volumes (Appendix 1C).

Table 6-1: Sample Calculation of CO_2/CH_4 Volumetric Ratios, for Representative Depth Values

Depth (m)	Pressure (psi)	Temp. (° F)	CH_4 Z-factor	CH_4 B_g* (feet^3/scf)	CO_2 Z-factor	CO_2 B_g (feet^3/scf)	Volume Ratio CO_2/CH_4
1000	1420	99	0.840	0.00936	0.270	0.00301	**311%**
2000	2840	148	0.868	0.00526	0.450	0.00273	**193%**
3000	4261	198	0.968	0.00423	0.625	0.00273	**155%**
4000	5681	247	1.077	0.00379	0.765	0.00269	**141%**

* Bg = Formation volume factor

6. CO_2 Sequestration Potential. The volumetric estimate computed in part 5 above was then converted to mass at STP conditions. We estimated a significantly larger overall CO_2 injection potential than previous studies, for two main reasons. First, we used the USGS estimate of global ultimate recoverable natural gas resources (cumulative production plus reserves plus undiscovered resources), which is much larger than estimates based on extrapolating existing production rates. (As mentioned previously for oil, much of the current natural gas production comes from reserves that had not even been discovered several decades ago.) It is very likely that the natural gas resources evaluated by the USGS will be discovered and developed over the next few centuries.

Second, our more rigorous analysis of formation volume factors, discussed in part 5 above, shows that considerably more CO_2 per unit void space can be stored in depleted natural gas fields than previously estimated. As a conservative measure, we assumed that 75% of the void space created by exploiting natural gas fields could be replaced with carbon dioxide. The remaining 25% may not be usable due to field edge effects, water influx, or various other reasons. (As another conservative assumption, we did not include any additional sequestration capacity that may exist in reservoirs where the original natural gas reserve was less than that required to fill up the reservoir to the "spill point.") Sequestration volumes and costs were converted into metric units of Gt and $/t. The 155 individual estimates were then sorted, cumulated, and graphed in **Figure 6-4**. Sequestration costs for depleted oil and natural gas fields (combined) are shown in **Figure 6-5.**

The global ultimate CO_2 sequestration potential for depleted natural gas fields is estimated to be approximately 797 Gt. Assuming that CO_2 is supplied from power plant sources at costs of $53/tonne ($3.00/Mcf), unit sequestration costs are expected to range from about $60/t to over $150/t. Largely because large volumes of relatively low-cost CO_2 sequestration capacity are expected to gradually emerge in Russia and the Middle East, the global weighted average sequestration cost is estimated at about $72/t.

The use of less costly waste CO_2 from natural gas processing plants ($18/t or $1.00/Mcf) (or technological improvements that reduce CO_2 capture costs from power plants to a comparable level) would reduce the average sequestration cost in natural gas fields to about $34/t. (No estimate was made of sequestration costs for natural CO_2, since that development would be highly unlikely). Sequestration in natural gas fields is much more costly than in depleted oil fields with enhanced oil recovery potential, because there are no economic benefits to injecting CO_2 into depleted gas fields (Appendix 1C).

Fig 6-4

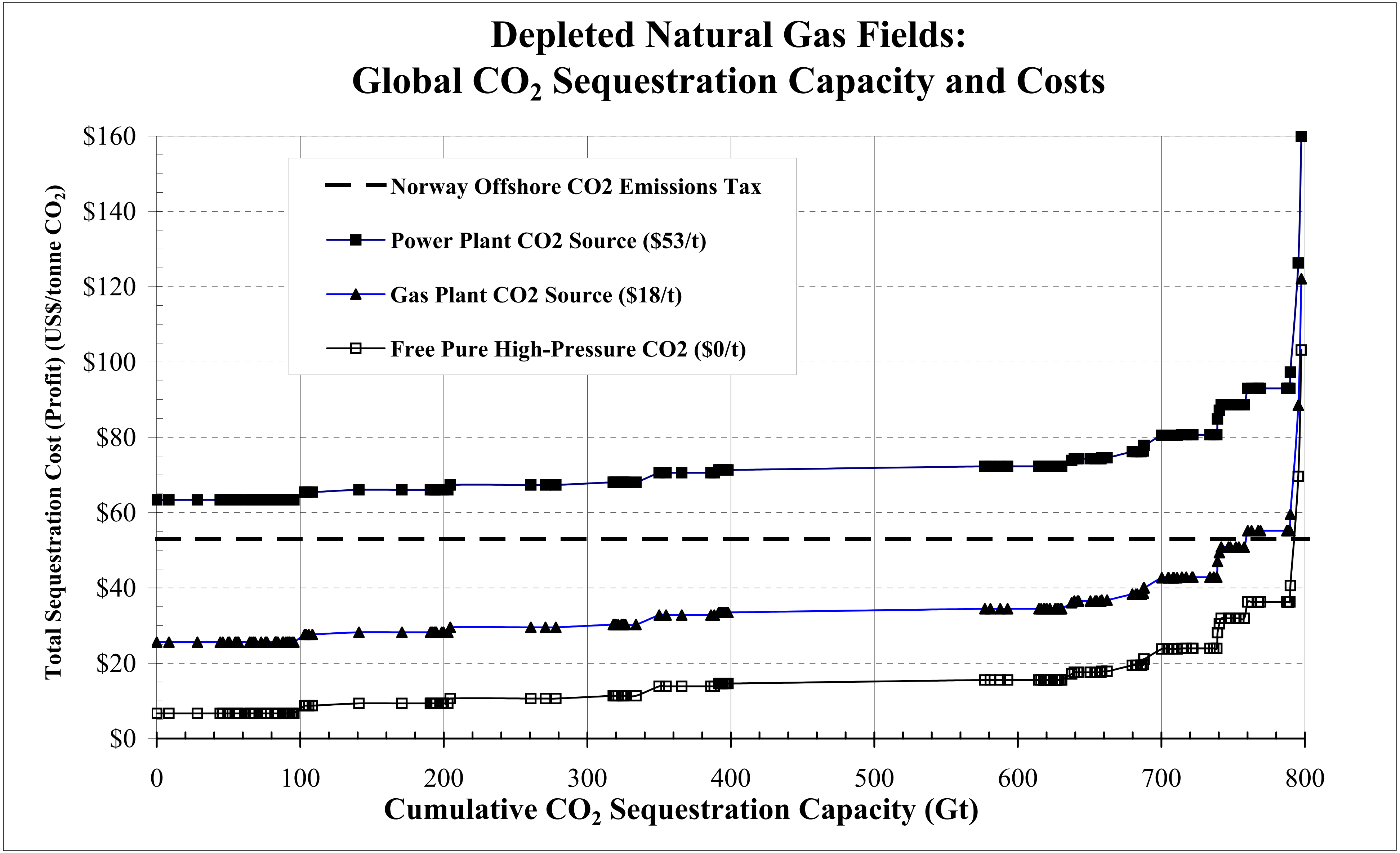
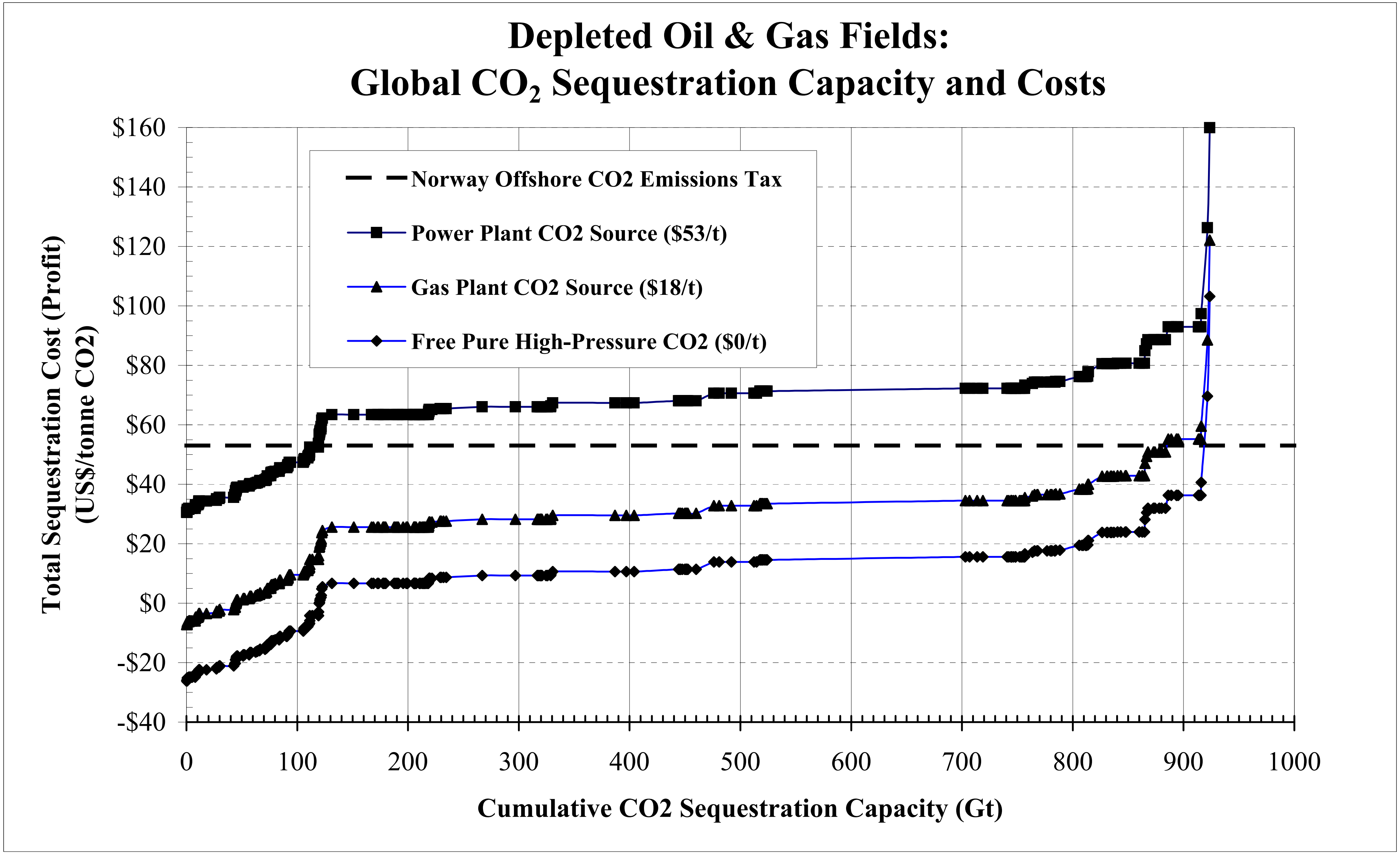

Depleted Natural Gas Fields:
Global CO2 Sequestration Capacity and Costs
Norway Offshore CO2 Emissions Tax
Power Plant CO2 Source ($53/t)
Gas Plant CO2 Source ($18/t)
Free Pure High-Pressure CO2 ($0/t)
Total Sequestration Cost (Profit) (US$/tonne CO2)
$0
$20
$40
$60
$80
$100
$120
$140
$160
0
100
200
300
400
500
600
700
800
Cumulative CO2 Sequestration Capacity (Gt)

Fig 6-5



Depleted Oil & Gas Fields:
Global CO_2 Sequestration Capacity and Costs
Norway Offshore CO2 Emissions Tax
Power Plant CO2 Source ($53/t)
Gas Plant CO2 Source ($18/t)
Free Pure High-Pressure CO2 ($0/t)
Total Sequestration Cost (Profit)
(US$/tonne CO2)
$160
$140
$120
$100
$80
$60
$40
$20
$0
-$20
-$40
0
100
200
300
400
500
600
700
800
900
1000
Cumulative CO2 Sequestration Capacity (Gt)

7.0: Barriers to Implementation

7.1 Introduction

Despite the large potential for sequestering carbon dioxide in depleted oil and gas fields -- at moderate cost or even at a profit in the more favorable settings -- the current level of anthropogenic CO_2 sequestration activity, while noteworthy, is still relatively small (about 3 million tonnes/year; 55 Bcf/year in EOR projects). A number of technical and economic obstacles to wider application of this technology have been identified. These barriers need to be overcome before sequestration of anthropogenic CO_2 in depleted petroleum fields can be implemented on a large scale, sufficient to meaningfully impact atmospheric CO_2 concentrations. This final section evaluates the principal "barriers to implementation" which could be inhibiting the full storage potential of depleted oil and gas fields. We conclude the section with recommendations for future R&D and policy studies, which could help to overcome these barriers.

Several other groups are also examining barriers to implementation. For example, the U.S. Department of Energy has recently released its broad Carbon Sequestration R&D plan, which included discussion of technological research needs (U.S. DOE, 1999). In addition, BP Amoco, U.S. DOE and IEA GHG jointly sponsored a workshop on the topic (BP Amoco, 1999). The BP Amoco workshop convened a wide range of specialists in the areas of CO_2 capture, processing, EOR, ECBM, geologic sequestration, and policy to debate the challenges and potential of geological sequestration technology. We have integrated issues raised by these reports with our earlier discussions with industry specialists.

The principal barriers to broader implementation of CO_2 sequestration technology are:

- **Reservoir.** Two fundamental potential barriers are the effectiveness of the reservoir as a CO_2 disposal site and the optimal operation of the CO_2 sequestration process. Fortunately, as discussed extensively in Section 3, the petroleum industry has the significant benefit of a great wealth of public information and technology that have been developed by commercial CO_2-EOR and underground gas storage (UGR) projects. Both EOR and UGR activities are mature and technically advanced multi-billion dollar enterprises. The degree to which the needed technology and understanding for CO_2 sequestration in depleted oil and gas fields exists "off the shelf" should not be underestimated. Within this rather optimistic viewpoint, however, there remain two second-order reservoir-related challenges: how best to adapt existing petroleum technology and facilities to CO_2 storage, and how to gauge the long-term physical and chemical impacts on the reservoir rock and fluid. Furthermore, each local petroleum province and specific depleted field will present its own particular reservoir challenges to CO_2 sequestration, requiring extensive field-specific studies and testing.

- **CO_2 Sources.** As documented in the economic model developed in Section 6, capturing and processing CO_2 remains by far the largest single cost associated with sequestration in depleted oil and gas fields (as it is for most CO_2 sequestration methods). In contrast with relatively mature reservoir technology summarized above, the capturing and processing of CO_2 from anthropogenic waste streams is technically immature. Transporting and injecting CO_2 also can represent significant costs in the sequestration process, but these technologies – again developed and refined by the EOR and UGR industries -- are fairly mature and efficient. Much more work also remains in characterizing the important anthropogenic CO_2 waste streams relative to candidate storage sites.

- **Environmental & Safety.** Early studies have begun to examine the environmental impacts of CO_2 storage operations on the reservoir and surrounding area, but these potential safety risks and their mitigation require additional study. Again, the operation of natural CO_2 production fields and UGR facilities offer many insights into environmental and safety issues related to sequestration.

- **Economics.** The performance of commercial EOR projects provides a basis for evaluating the full-cycle costs of storing CO_2 within depleted oil fields. UGR facilities likewise can provide insight into the economics of sequestration in depleted gas fields. However, these costs will vary widely depending on location and setting. Regardless of the generalized economic assessment that we have performed in Section 6, each individual sequestration site will require a more detailed economic (as well as technical) evaluation.

- **Regulatory:** Perhaps the least mature area for CO_2 sequestration is the regulatory framework that can allow this activity to be routinely performed and monitored. Again, the United States has the most extensive experience in the transportation, injection, and monitoring of CO_2 in depleted oil fields. UGS regulation is mature in North America, Europe and Australia. However, uncertainly remains about future regulation of CO_2 sequestration, and the concern of residents not previously exposed to the practice of underground injection (such as in extreme northeastern U.S.) must be considered.
- **Commercial:** Commercial barriers are real and substantial. A principal potential commercial barrier is likely to be optimization of optimal petroleum production with CO_2 storage. The procedure for valuing disused fields and transferring ownership rights, as disused fields are converted into storage sites, is also a particularly thorny issue requiring further study.

To address these issues, we discussed the technological and commercial challenges of CO_2 sequestration with more than one dozen oil and gas field operating companies. In addition, we incorporated selected ideas presented by the U.S. DOE Carbon Sequestration Road Map and the BP Amoco Sequestration workshop. Section 7 incorporates the findings of these two independent efforts to investigate the principal barriers to implementation.

Below, we discuss in turn the principal Barriers to Implementation affecting CO_2 sequestration, and suggest recommendations for further R&D and policy work that could bring about their resolution:

7.2 Reservoir/Technological Barriers

We have discussed the issues of reservoir criteria and technology application needed for effective sequestration of CO_2, in the context of actual CO_2-EOR floods. A great wealth of information and insight about the injection and storage of CO_2 in depleted oil and gas fields may be gleaned from these commercial EOR projects and from commercial natural gas storage projects. This massive body of knowledge provides depleted oil and gas field settings with a considerable advantage over other relatively less well tested sequestration technologies, such as aquifer storage and deep ocean injection, which are still at an early experimental (non-commercial) stage.

Nearly all participants agree that many of the basic technologies for sequestering CO_2 in depleted oil and gas fields already exist and could be applied "off the shelf" with only minor adaptation and optimization. A recent analysis of CO_2 injection technologies used by EOR and natural gas storage operators supports this view, demonstrating the relative ease with which these technologies could be applied to CO_2 sequestration in depleted oil and natural gas fields (Gunter et al., 1998).

However, the effective selection, application and management of petroleum production and storage technologies to CO_2 sequestration only now is being considered. There currently are no "Best Practices" for CO_2 sequestration in depleted oil and gas fields. A great deal of R&D and engineering work is required in terms of detailed screening, analysis, and refining the design and application of CO_2 sequestration systems within individual petroleum provinces. The current study can only supply a broad-brush overview of the worldwide potential. To implement sequestration, each candidate reservoir would need to be studied in detail to determine the efficacy and optimal design of CO_2 sequestration and potential EOR. Following design, each CO_2 injection project would then be tested on a pilot scale, further refined, and then implemented on a larger scale.

Governmental R&D organizations can help to stimulate development of the incremental technological improvements that will be needed to demonstrate and reduce the costs of CO_2 sequestration in depleted oil and gas fields. This effort could take the form of targeted R&D into topics such as assessment of physico-chemical changes in the reservoir, optimal injection and monitoring technologies, demonstration pilots at representative fields, and the challenges of optimizing petroleum recovery with CO_2 sequestration. Actual operation of CO_2 sequestration facilities at depleted oil and natural gas fields would probably be most efficiently performed by private-sector commercial enterprises, within a regulated system of tradable sequestration credits and verification.

Effects of CO_2 Flooding on Reservoir Oil and Rock

The long-term effects of CO_2 sequestration on the integrity of the reservoir rock and the quality and recoverability of reservoir oil are poorly understood. Depleted oil fields that are converted to CO_2 storage almost certainly will have large and economically significant remaining resources of oil. Even though most residual oil deposits may not be economically recoverable at the time the field is converted to CO_2 sequestration, future higher oil prices and/or the development of more effective alternative CO_2 disposal technologies could lead to re-conversion of the field back to oil production. Therefore, it is essential to consider the effects of CO_2 flooding on the value and producibility of depleted oil resources.

The only empirical published account of the effect of CO_2 flooding on reservoir oil is a relatively short-term study performed at Chevron's McElroy field in the Permian basin, West Texas, U.S.A. (Hwang and Ortiz, 1998). This study monitored changes in oil composition during 1992 and 1993, soon after CO_2 flooding commenced in this portion of the field. Although injected CO2 had little effect on saturated and aromatic hydrocarbons, over the relatively short eighteen-month time period, several significant changes in oil composition were noted.

Sulfur content increased shortly after the start of CO_2 injection, by 0.2 to 0.3%, probably due to bacterial reduction of dissolved sulfate (SO_4^{-2}) to elemental sulfur and H_2S, which are soluble. Increasing sulfur content could slightly reduce the value of produced crude, but would not in itself be expected to affect its technical recovery.

Fractionation of heavy hydrocarbons and asphaltene precipitation from the fluid phase were potentially more serious effects of CO_2 injection. Asphaltene levels were significantly reduced at the McElroy flood, to about one-half of pre-flooding levels. Asphaltene precipitation from the fluid phase can result in formation damage and reduction in petroleum recovery. The McElroy field experienced a 40% reduction in water injectivity in the CO_2 pilot area, probably because of asphaltene precipitation into reservoir pore throats.

The long-term impacts of CO_2 injection on oil recovery in depleted fields may be even more significant, as sulfur reduction and asphaltene precipitation increase with time. Clearly, further research is needed on the long-term chemical and physical impacts of CO_2 on reservoir rock and fluids. The most effective mechanism for addressing this barrier would probably be government/industry sponsored R&D focused on the near-term sequestration targets, probably for the Permian, Gulf Coast, and Rocky Mountain regions of North America, as well as the North Sea.

Recommendations. Evolutionary R&D in the following areas, leveraging from off-the-shelf petroleum extraction technologies, could address this barrier during the near- to medium-term (1-10 years).

- ***CO_2 – Rock/Fluid Interaction:*** Further research is needed to quantify the chemical and physical reaction of injected CO_2 with rock and fluid in a variety of reservoir settings. Major permeable rock types including sandstone, siltstone, carbonate, and salt should be studied, as should interaction of CO_2 with hydrocarbon and other formation fluids.

- ***Reservoir Studies:*** The efficacy of CO_2 injection and EOR in the Permian and Rocky Mountain basins of the United States, discussed extensively in this report, is relatively well documented. As Section 5 showed, however, the feasibility of CO_2 flooding in other petroleum provinces is still poorly understood. Representative depleted oil and gas fields from the top-ranked petroleum provinces, particularly outside the United States, should be selected for detailed feasibility study, using accepted EOR screening methods that are already in place.

- ***Reservoir Models:*** Existing industry numerical simulation models need to be improved to enable them to explicitly address CO_2 sequestration, both in depleted oil and gas fields. Such models will be essential for operating sequestration projects, as well as providing supporting documentation and verification for emissions trading.

- ***Natural CO_2 Fields:*** The three large natural CO_2 fields in the western U.S. that have been developed for production (McElmo, Bravo and Sheep Mountain Domes) constitute a convenient laboratory for evaluating the storage and movement of CO_2 within a reservoir. The geology and operation of these fields, and any well-documented natural underground CO_2 deposits in other countries, should be studied in detail to evaluate the long-term integrity and chemical interaction of CO_2 within underground reservoirs.

7.3 CO_2 Supply Barriers

In Section 6, we discussed estimates for the costs of alternative carbon dioxide supplies, both natural and anthropogenic. Our economic analysis of CO_2 injection into depleted oil and gas fields identified the high cost of CO_2 supply from anthropogenic sources as one of the most important barriers to the adoption of this technology for sequestration. It is extremely expensive to capture, separate, process, compress, and transport CO_2 from anthropogenic sources to the depleted petroleum field. This is why naturally occurring, pure, high-pressure CO_2 supplies have dominated most of the EOR market in the Permian basin.

EOR operators utilize natural CO_2 sources where those sources are readily available and close to the depleted field, simply because natural CO_2 generally is the lowest-cost source for this costly injectant. For example, natural CO_2 at high purity and high pressure costs approximately \$0.65/Mcf in the Permian basin of the southwestern United States. In contrast, the total capture, processing, and compression costs for waste CO_2 from natural gas processing plants (probably the cheapest anthropogenic source of CO_2) is estimated to be approximately \$1.00/Mcf (\$18/t). As discussed in Section 2.0, several substantial EOR operators are currently injecting waste CO_2 from natural gas plants and fertilizer plants (**Table 2-2**).

CO_2 supplies from power plant flue gas are significantly more costly, an estimated \$3.00/Mcf (\$53/t) or higher. No EOR operator is using power plant flue gas sources for CO_2 injectant, simply because it is too expensive and there currently are no emission reduction credits supporting such activities. Our economic analysis presented in Section 6 indicates that the high current supply cost of anthropogenic CO_2 is a principal (probably the major) barrier to the expanded use of this injectant source within depleted oil fields. In addition, no operator is injecting CO_2 (anthropogenic or otherwise) into a depleted gas field; again, without CO_2 emission reduction credits there simply is no rationale for such activities.

Some of the key conclusions of the BP Amoco Houston workshop were that separation of CO_2 from nitrogen and other components in a typical power plant represents a major energy and pressure loss. The most promising research areas for lowering CO_2 capture costs were identified to be:

- ***Oxygen Firing:*** Use of recycle or partial oxygen firing could raise CO_2 concentrations in flue gas, well above the 3% (gas turbine) to 12% (steam turbine) levels currently achieved. Oxyfuel technologies that could be ready for demonstration within 1 to 3 years include: O2/CO2 boilers with turboexpander to scavenge waste heat; Heat Recovery Steam Generation retrofitted to existing gas turbines; and direct oxyfuel-fired high-pressure steam generation, which produces a pure CO_2 waste stream for injection.

- ***Amine Separation:*** This near-term process consumes large amounts of energy, which could be provided through scavenging of waste heat from energy production. Improved solvents, which could reduce energy requirements, are under development by IGT, Mitsubishi, and ABB.

- ***Pre-Combustion Decarbonization:*** Reforming or gasifying the fossil fuel generates a hydrogen-rich stream that combusts without forming CO_2. Medium-term technologies include optimizing gas turbines for hydrogen combustion and high-efficiency reformer systems, such as inorganic membranes or flameless distributed combustion. In the longer term, replacing combustion turbines with fuel cells for power generation would remove the need for both CO shift conversion and removal of CO_2 from the hydrogen stream.

- ***Advanced Methods:*** Longer term R&D could be directed to electric swing adsorption, membranes, hydrates, cryogenic condensation, as well as hybrid systems. For example, in cold climates CO_2 could be separated from flue gas to form a water hydrate. This slurry could then be injected into an underground reservoir, where it would melt and provide injectant for EOR, ultimately to be sequestered within immobile oil.

Reducing the costs of CO_2 capture, processing, and transport from anthropogenic sources (such as power plants) is perhaps the single most important R&D area for the sequestration community. Technological advancement in these areas could be catalyzed by government-supported R&D. Once a viable commercial sequestration industry is in place, private-sector R&D in capture technology is likely to grow rapidly.

Recommendation. Given that the costs of capturing and processing anthropogenic CO_2 represent fully two-thirds of the full-cycle costs of sequestration in depleted oil and gas fields, a strong government/industry R&D program into improving capture and processing technologies is essential. Lower CO_2 capture costs would also benefit other sequestration activities, such as aquifer and ocean disposal. An effective government and industry development program could be:

- ***Basic R&D:*** Competitive, government-funded basic R&D into novel CO_2 capture/processing technologies, discussed above.

- ***Field Application:*** Joint industry/government funded programs to test CO_2 capture and processing technologies in depleted oil and gas field applications.

- ***Mapping of CO_2 Sources vis-à-vis Reservoirs:*** An extremely useful product would be a comprehensive GIS data base with locational information on major anthropogenic CO_2 sources, along with adjacent depleted oil and gas fields positions and storage capacities/characteristics. (Other potential geological reservoirs, such as aquifers and coal deposits, could also be included.) Such an information system could be used to greatly improve the precision of the economic analysis performed in this report. It could be distributed to industry to allow emitter to evaluate their particular geological sequestration options.

7.4 Environmental and Safety Barriers

Carbon dioxide can be a hazardous substance, if it is leaked catastrophically from an underground reservoir. Holloway (1996) and Cox et al. (1996) assessed the literature of case studies of catastrophic natural emissions of CO_2 from volcanic eruptions and seepages. Monitoring of CO_2 in the reservoir is essential to preclude accidents, and to convince regulatory authorities and parties with a commercial interest that sequestration is real and permanent.

Leakage of CO_2 from underground reservoirs could occur in two ways. First, CO_2 could leak from the reservoir through or around a CO_2 injection well. Modern petroleum well completion practices typically include pressure testing of steel tubulars and cement within the well to check for leakage. If identified, leakages are then squeezed off using zone isolation packers and cement. Such operations are routinely performed primarily for economic efficiency of petroleum production, rather than for safety. One exception is the completion of underground water disposal wells, where safeguarding potable water supplies is the main objective. In a CO_2 sequestration operation, rapid leakage of CO_2 would be easily identified by anomalies in well injection and monitoring pressures. Remediation of the well could then be taken to rectify most leakage problems.

Second, more diffuse and gradual emission of CO_2 could occur by migration along stratigraphic bedding or fault planes within the reservoir. Depleted oil and gas fields – which may have stored hydrocarbons for millions of years -- are by their very nature unlikely to release large volumes of injected CO_2. In summary, these authors concluded (and we agree) that it was extremely unlikely that CO_2 sequestration in depleted oil and gas fields would lead to a sudden emission of dangerous ground-hugging plumes of CO_2.

New technologies could be employed to track more closely the movement of CO_2 within the disposal reservoir, to detect possible leakage and emission. For example, highly advanced geophysical surveys are being applied to directly detect the movement of CO_2 within EOR projects over time (Benson and Davis, 1999). This technology employs 4-dimensional (4-D, with time as the fourth dimension), 3-Component (3-C, recording all three shear-wave directions) seismic reflection data. Multiple surveys shot in the same location over time can track changes in rock and fluid properties, helping to improve oil recovery and direct monitoring of CO_2 flow.

Recommendation. Monitoring and verification of CO_2 sequestration is a key area to provide scientific confidence that CO_2 sequestration is taking place, and to convince regulators and the general public that sequestration is measurable and long-lived. Research areas could include:

- ***Current EOR and UGR Technologies:*** Field testing of existing monitoring techniques that currently are used widely by the EOR and UGR industries, such as petrophysical, geochemical, and production logging; well testing and sampling; pressure monitoring and sampling wells; and reservoir simulation.

- ***Advanced Methods:*** Medium-term technologies include 4-dimensional, 3-component seismic monitoring; gravity; and other geophysical and petrophysical techniques. Advanced reservoir models that more accurately reflect the interactions between injected CO_2 and reservoir fluids and strata also are needed.

- ***Natural CO_2 Fields:*** As discussed in Section 7.2, the three large natural CO_2 fields in the western U.S. that have been developed for production (McElmo, Bravo and Sheep Mountain Domes) constitute a convenient laboratory for evaluating the storage and movement of CO_2 within a reservoir. The geology and operation of these fields should be studied in detail to evaluate the stability, safety and environmental impacts of long-term CO_2 storage within underground reservoirs.

7.5 Economic Barriers

In Section 6, we discuss our economic model of worldwide sequestration in depleted oil and gas fields. Economic barriers to sequestration of anthropogenic CO_2 in depleted oil and natural gas fields certainly exist and were quantified. Rather than repeating the specifics of sequestration economics in any one region, which is better shown by the model output provided in Appendix 1, we simply reiterate the underlying reasons for its poor economic performance. (These barriers are discussed in greater detail in the other parts of this section.)

The two principal economic barriers to sequestration are: high supply costs for capturing, processing, and compressing anthropogenic CO_2, and the lack in most countries of any credit system for so that operators may financially benefit from CO_2 sequestration activities. High supply costs for capturing, processing, and compressing CO_2 are expected to be reduced gradually through targeted R&D and by larger economies of scale. The lack of a credit system for CO_2 sequestration is discussed below, under regulatory barriers.

7.6 Regulatory Barriers

In the United States, state-level government agencies generally have authority to regulate most oil and gas production activities, including CO_2-EOR. These agencies will approve most applications that include a credible and well-documented plan for injecting CO_2 into a depleted oil or gas field. Such permit applications typically address surface impacts, well completion design, operational procedures, protection of potable aquifers, and other concerns. The approval process generally requires one to several months to complete in petroleum producing states. Non-petroleum producing states may require longer review, estimated at up to one year. Short-term, limited testing permits generally require less documentation than large-scale and long-term commercial operations.

Interstate transport of CO_2 through large pipelines (up to 900 km in length) already takes place; this is handled through a federal-level pipeline regulatory body. In summary, there are no significant regulatory barriers in the United States (either state or federal level) which interfere with the routine injection of CO_2 into a depleted oil and gas reservoir, including purely sequestration activities. (This is not to say that political concerns may not arise, most likely from residents living in the vicinity of the sequestration facility.)

The key regulatory barrier to expanded CO_2 sequestration in depleted oil and gas fields has been the lack of a tax (or credit) system that can provide for financial benefit to the operator of a CO_2 sequestration project. Currently, Norway is the only country to directly tax CO_2 emissions, and to allow operators to avoid taxes by sequestering CO_2. However, even Norway does not yet allow for the most efficient scheme, whereby the CO_2 emitter can pay for its choice of the lowest-cost emission reduction or sequestration option, including overseas activities.

A number of experimental tradable credit systems are currently under development, although none are in routine commercial operation. Some of the more significant systems are discussed below:

- **Greenhouse Gas Emission Reduction Trading** pilot (GERT) is a partnership of the Canadian federal government, several provinces and Canadian industry, and other groups. Formed in 1998, GERT is designed to test the mechanics of a national trading system for greenhouse gas emissions in Canada. A similar but more local organization based in the Windsor-Quebec corridor of Canada (PERT) has overseen pilot trades on CO_2 emissions between member companies.

- **Trans Alta Corp.**, an Alberta-based energy company that is Canada's leading producer of independent power, currently has a standing offer to purchase offset CO_2 credits at approximately $2/tonne. However, this price is considerably less than the $53/tonne tax on CO_2 emissions currently in place in Norway, and would probably not have a substantial impact on investment in CO_2-EOR projects.

- **Credit for Voluntary Reductions Act:** (U.S. Senate Bill S.547; formerly S.2617) This proposed legislation was introduced into the United States Senate on March 4, 1999. As currently envisioned, the proposal would provide businesses with legally binding credits for reducing their greenhouse gas emissions below a 1996-1998 emissions baseline. Such credits could then be sold or traded. Qualifying sequestration activities outside the U.S. would be limited to agricultural and nuclear power. This bill is still being shaped and changes are likely.

Recommendation. Close cooperation between industry and government is essential for the development of cost-effective sequestration technologies.

- ***Regulation:*** Currently there are few regulations specifically pertaining to CO_2 sequestration in depleted oil and gas fields, although CO_2 injection is addressed under existing oil and gas regulations, at least in the U.S. As the BP Amoco Houston Workshop report cogently states *"There is an opportunity for industry to proactively influence the regulatory process to ensure that the rigor associated with measurement and verification standards for* *underground CO_2 repositories is consistent with the degree of risk they pose."* Industry could start by demonstrating how CO_2 and gas injection activities have been safe and effective in the EOR and UGR sectors. A workshop, modeled after the BP Amoco Houston workshop, could be convened with both industry and government participants to focus explicitly on regulation of CO_2 sequestration and monitoring.

- ***Emissions Trading:*** As discussed above, a number of policy and industry groups are working to establish a functioning CO_2 emissions trading system. The cost/sequestration curves generated by this study provide a general indication of the impact such emissions credits could have in bringing on additional economically viable sequestration capacity. This economic evaluation, and further refinements, should be communicated to all parties active in the emissions trading debate. Intra-company CO_2 emissions trading systems, such as recently established by Shell and BP Amoco, and the U.S. sulfur emission trading system could be studied as small-scale analogs for a global CO_2 emssion trading system.

7.7 Commercial Barriers

One of most serious potential barriers to CO_2 sequestration in depleted oil and natural gas fields may be commercial or organizational conflicts between petroleum recovery and CO_2 sequestration. The overall objectives and daily field operational procedures can differ significantly for these two activities. There is no precedent for simultaneous operation of oil and gas production with intentional sequestration, particularly wherein sequestration is a wholly separate commercial enterprise.

Transferring ownership from the petroleum rights holder of a depleted oil or natural gas field to a separate sequestration rights holder is another untested and undoubtedly complex procedure. Depleted oil and natural gas fields always leave behind some amount of residual petroleum within the reservoir. New technologies or changes in price/cost relationships -- unforeseen and inherently unpredictable -- can turn an abandoned depleted field into a valuable asset once again. But converting a depleted field into a sequestration site may be irreversible, at least if sequestration is intended to be permanent and credits meaningful and verifiable.

Natural Gas Storage Conflicts: Depleted gas production fields located close to demand centers often live a second life of natural gas storage operations. Gas storage fields are used to smooth out seasonal supply and demand variability, buying and injecting natural gas during low-demand periods (typically summer) and withdrawing supplies during high demand (winter). Given their close proximity to gas demand (and therefore inevitably CO_2 emission) centers, these are indeed the very fields that will be in demand for sequestration.

Using depleted gas fields for storage will compete with sequestration and, depending on the value of emissions credits, may even be a higher-value commercial activity. But once CO_2 injection into a depleted gas field begins, the residual gas resource will rapidly be contaminated, destroying any residual gas storage value. The most efficient transfer method may be to allow the current gas production/storage rights holder to auction off the field to the highest bidder, whether for production, storage, or sequestration uses. In this way (barring information barriers), the market system should be able to accurately set alternative values, and price sequestration rights accordingly.

EOR Conflicts: The potential conflicts with depleted oil fields are more subtle and possibly even more complex than in depleted gas fields. In a routine EOR project, the operator seeks to minimize CO_2 injection and sequestration, while maximizing oil recovery. This is because CO_2 is a costly commodity and the largest single capital or operating expense. But from a sequestration point of view, more credits obviously will be earned by maximizing sequestration.

The most efficient solution may be to assign any sequestration rights to the current petroleum production rights holder. For inactive fields, joint petroleum recovery and sequestration rights could be auctioned by the government. In this way, the field operator could maximize its total return on investment for both EOR and sequestration activities. This would also enable the field operator to respond rationally to changes in oil prices, technology, costs, and the market value of traded sequestration credits. Joint ownership also would preclude conflicts between separate petroleum rights and sequestration rights holders.

Recommendation. There exists a need for a detailed engineering analysis of a specific depleted oil field to characterize and assess potential conflicts between CO_2-EOR and CO_2 sequestration. This could best be performed at a new, greenfields EOR project, such as at PanCanadian's Weyburn EOR flood in Saskatchewan, Canada or BP Amoco's planned EOR project on the North Slope of Alaska, U.SA. Issues requiring assessment include:

- ***EOR vs. Sequestration.*** Economic evaluation of optimal CO_2/oil ratio, given likely future oil prices and values for CO_2 sequestration credits. Selection of CO_2 injection zones, pressures, and schedules to optimize sequestration and EOR.

- ***Green Fields vs. Depleted Fields.*** Injected water needs to be minimized, because water and CO_2 compete for space in the reservoir. Injecting CO_2 during the early stages of reservoir exploitation could improve oil recovery while simultaneously maximizing CO_2 sequestration. This concept requires detailed evaluation.

- ***Gas Recovery vs. Sequestration:*** The use of CO_2 to maintain reservoir pressure or as base gas for underground gas storage in depleted gas fields has been proposed, even though the risk of costly contamination of natural gas reserves is obvious. This concept also requires evaluation.

In conclusion, multiple barriers to CO_2 sequestration in depleted oil and gas fields exist. However, these impediments may be overcome with a sustained program of basic and applied research into CO_2 capture and underground injection technologies. This technical program should be coupled with policy debate between industry, government, and other groups to help establish an emissions reduction trading system, as well as confidence in the safety and integrity of the sequestration process.

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Appendix 1: Economic Model Output

Appendix 1A:

Worldwide Petroleum Production, Reserves, Resources

Rank Oil/Gas (BOEE)	USGS Code	Province Name	Region	Country	Cum. Prod.+Reserves Oil (BB)	Gas (Tcf)	NGL (BB)	Total (BBOE)	Undiscov. Resources Oil (BB)	Gas (Tcf)	Total (BBOE)	Ult. Recoverable Oil (BB)	Gas (Tcf)	Total (BBOE)	Cum % World BBOE
1	1174	West Siberian Basin	CIS	Russia	140.4	1271.8	3.1	355.5	40.0	900.0	190.0	183.5	2171.8	545.5	13.2%
2	2024	Mesopotamian Foredeep	Mid-East	Kuwait	292.4	298.3	1.8	343.9	45.5	153.4	71.1	339.7	451.7	415.0	23.2%
3	2030	Zagros Fold Belt	Mid-East	Iran, Iraq	121.6	399.4	1.4	189.6	18.9	205.4	53.1	141.9	604.8	242.7	29.0%
4	2021	Greater Ghawar Uplift	Mid-East	Saudi Arabia (EC)	141.7	248.6	8.6	191.7	22.1	127.8	43.4	172.4	376.4	235.1	34.7%
5	2019	Rub Al Khali Basin	Mid-East	Saudi Arabia (SE)	89.9	182.3	2.6	122.9	14.0	93.8	29.6	106.5	276.1	152.5	38.4%
6	2022	Qatar Arch	Mid-East	Qatar, UAE	1.2	465.6	13.8	92.6	0.2	239.4	40.1	15.2	705.0	132.7	41.6%
7	1016	North Caspian Basin	CIS	Kazakhstan	10.8	156.9	8.9	45.9	30.0	150.0	55.0	49.7	306.9	100.9	44.0%
8	4025	North Sea Graben	Europe	Norway, UK, Denmark	44.1	160.6	6.0	76.9	8.7	35.0	14.5	58.8	195.6	91.4	46.2%
9	5047	Western Gulf	N. America	USA (SC)	26.9	251.6	7.5	76.3	14.3	2.5	14.7	48.7	254.1	91.1	48.4%
10	1015	Volga-Ural Region	CIS	Russia	64.0	99.2	1.1	81.6	2.5	4.0	3.2	67.6	103.2	84.8	50.4%
11	7192	Niger Delta	Africa	Nigeria/Cameroon	34.8	93.9	2.8	53.3	5.1	150.0	30.1	42.7	243.9	83.4	52.4%
12	5305	Villahermosa Uplift	N. America	Mexico (S)	35.0	41.3	0.1	42.0	23.0	76.3	35.7	58.1	117.6	77.7	54.3%
13	6099	Maracaibo Basin	S. America	Venezuela	49.1	26.7	0.1	53.7	8.0	46.0	15.7	57.2	72.7	69.3	56.0%
14	6098	East Venezuela Basin	S. America	Venezuela, Trinidad	30.2	129.7	0.7	52.5	8.5	36.0	14.5	39.4	165.7	67.0	57.6%
15	5044	Permian Basin	N. America	USA (SW)	32.7	94.0	6.7	55.1	1.5	15.0	4.0	40.9	109.0	59.1	59.0%
16	1154	Amu-Darya Basin	CIS	Turkmenistan	0.8	230.4	1.2	40.4	3.0	75.0	15.5	5.0	305.4	55.9	60.4%
17	5243	Alberta Basin	N. America	Canada	15.0	93.7	2.3	32.9	5.0	100.0	21.7	22.3	193.7	54.6	61.7%
18	2043	Sirte Basin	Mid-East	Libya	36.7	37.7	0.1	43.1	5.7	16.0	8.4	42.5	53.7	51.5	62.9%
19	5097	Gulf Cenozoic OCS	N. America	USA (SC)	11.9	140.3	0.0	35.3	0.3	92.0	15.6	12.2	232.3	50.9	64.2%
20	2070	Mediterranean Basin	Mid-East	Libya/Italy/Turkey/Greece/Egypt	0.1	12.5	0.4	2.6	0.0	264.0	44.0	0.5	276.5	46.6	65.3%
21	1112	S. Caspian Sea	CIS	Azerbaijan, Iran, Turkmenistan	17.4	36.0	0.5	23.9	6.0	30.0	11.0	23.9	66.0	34.9	66.1%
22	5001	N. Alaska	N. America	USA (NW)	14.4	33.0	1.1	21.0	5.0	50.0	13.3	20.5	83.0	34.3	67.0%
23	3127	Bohaiwan	E. Asia	China	24.6	15.7	0.1	27.3	4.5	5.0	5.3	29.2	20.7	32.7	67.7%
24	1008	Timan-Pechora Basin	CIS	Russia (NC)	13.2	36.6	0.7	20.0	4.0	25.0	8.2	17.9	61.6	28.2	68.4%
25	2058	Grand Erg/Ahnet Basin	Mid-East	Algeria	0.5	114.2	5.0	24.5	0.1	10.3	1.8	5.6	124.5	26.4	69.1%
26	4035	NW German Basin	Europe	Germany	2.3	141.7	0.1	26.0	0.0	0.0	0.0	2.4	141.7	26.0	69.7%
27	7203	West-Central Coastal B.	Africa	West Coast	14.5	12.2	0.1	16.6	5.0	25.4	9.2	19.6	37.6	25.9	70.3%
28	2054	Trias/Ghadames Basin	Mid-East	Algeria	15.3	25.1	1.0	20.5	2.4	2.3	2.8	18.7	27.4	23.3	70.9%
29	5058	Anadarko Basin	N. America	USA (C)	2.2	93.1	2.8	20.5	0.4	13.9	2.7	5.4	107.0	23.2	71.4%
30	2023	Widyan B.-Inter. Platform	Mid-East	Iraq	17.4	7.4	0.1	18.7	2.7	3.8	3.3	20.2	11.2	22.1	72.0%
31	1109	Middle Caspian Sea B.	CIS	Kazakhstan	9.6	28.7	0.1	14.5	3.5	15.0	6.0	13.2	43.7	20.5	72.5%
32	5048	East Texas Basin	N. America	USA (SE)	9.2	34.8	1.6	16.6	1.2	14.7	3.7	12.0	49.5	20.3	72.9%

33	3702	Greater Sarawak Basin	SE Asia	Malaysia	0.8	82.3	0.4	14.9	0.7	25.0	4.9	1.9	107.3	19.8	73.4%
34	3144	Songliao Basin	E. Asia	China (NE)	15.5	1.7	0.0	15.8	2.0	10.0	3.7	17.5	11.7	19.5	73.9%
35	5049	Louisiana-Miss. Salt B.	N. America	USA (SE)	7.1	42.8	1.3	15.5	1.2	14.7	3.7	9.6	57.5	19.2	74.4%
36	1214	Lena-Vilyuy Basin	CIS	Russia (C)	0.0	10.4	0.2	1.9	0.0	100.0	16.7	0.2	110.4	18.6	74.8%
37	5010	San Joaquin Basin	N. America	USA (SW)	13.8	12.5	0.7	16.6	1.2	2.5	1.6	15.7	15.0	18.2	75.2%
38	3154	Tarim Basin	E. Asia	China	0.7	5.0	0.2	1.7	11.0	30.0	16.0	11.9	35.0	17.7	75.7%
39	6035	Campos Basin	S. America	Brazil	10.1	6.2	0.1	11.2	5.7	2.0	6.0	15.9	8.2	17.3	76.1%
40	3701	Baram Delta/Brunei-Sabah B.	SE Asia	Brunei, Malaysia	6.9	36.2	0.2	13.1	1.6	11.6	3.5	8.7	47.8	16.7	76.5%
41	3808	Central Sumatra Basin	SE Asia	Indonesia	13.2	3.9	0.1	14.0	1.7	4.0	2.4	15.0	7.9	16.3	76.9%
42	3703	Malay Basin	SE Asia	Malaysia, Thailand	3.7	48.3	0.3	12.1	2.0	10.0	3.7	6.0	58.3	15.7	77.3%
43	1009	Dnieper-Donets Basin	CIS	Ukraine	1.6	59.1	0.2	11.7	0.7	20.0	4.0	2.5	79.1	15.7	77.6%
44	4036	Anglo-Dutch Basin	Europe	Netherlands, UK	0.6	71.7	0.1	12.7	0.0	16.0	2.7	0.7	87.7	15.3	78.0%
45	3817	Kutei Basin	SE Asia	Indonesia	2.9	45.8	1.3	11.8	1.4	10.0	3.1	5.6	55.8	14.9	78.4%
46	1050	South Barents Sea Basin	CIS	Russia	0.0	70.0	0.1	11.8	3.0	0.0	3.0	3.1	70.0	14.8	78.7%
47	6032	Reconcavo B./Rifted Margin	S. America	Brazil	1.5	2.0	0.1	1.9	9.2	19.0	12.3	10.8	21.0	14.3	79.1%
48	8043	Bombay Basin	S. Asia	India	8.4	24.2	0.3	12.7	0.8	4.0	1.5	9.5	28.2	14.2	79.4%
49	2071	Red Sea Basin	Mid-East	Sudan	9.2	8.5	0.3	10.9	1.4	8.3	2.8	10.9	16.8	13.7	79.7%
50	2056	Illizi Basin	Mid-East	Algeria, Libya	3.7	45.1	0.9	12.1	0.6	4.1	1.3	5.2	49.2	13.4	80.1%
51	3948	Northwest Shelf	Australasia	Australia W)	1.1	56.7	1.0	11.6	0.7	6.0	1.7	2.8	62.7	13.3	80.4%
52	6041	Putamayo-Oriente-Maranon B.	S. America	Peru, Equador, Colombia	6.6	1.6	0.0	6.9	4.6	9.4	6.2	11.2	11.0	13.0	80.7%
53	5043	Palo Duro Basin	N. America	USA (SC)	1.8	48.4	2.1	12.0	0.1	0.0	0.1	4.0	48.4	12.1	81.0%
54	4017	Vestford-Helgeland	Europe	Norway	2.7	15.7	0.7	6.0	1.4	25.0	5.6	4.8	40.7	11.6	81.3%
55	3115	Jungger Basin	E. Asia	China (W)	6.8	2.4	0.0	7.2	3.0	8.0	4.3	9.8	10.4	11.5	81.5%
56	5014	Los Angeles Basin	N. America	USA (SW)	8.6	7.0	0.4	10.2	0.9	1.5	1.2	9.9	8.5	11.3	81.8%
57	1322	North Sakhalin Basin	CIS	Russia (E)	2.2	22.4	0.2	6.1	2.5	15.0	5.0	4.9	37.4	11.1	82.1%
58	6096	Llanos Basin	S. America	Colombia	5.4	10.3	0.2	7.3	2.0	4.0	2.7	7.6	14.3	10.0	82.3%
59	5300	Burgos/Sabinas/Parras B.	N. America	Mexico (NE)	0.1	8.1	0.2	1.7	0.2	48.0	8.2	0.5	56.1	9.9	82.6%
60	5215	Labrador-Newfoundland Shelf	N. America	Canada (E)	1.6	6.6	0.0	2.7	0.0	42.0	7.0	1.6	48.6	9.7	82.8%
61	4061	Carpathian-Balkanian Basin	Europe	Romania, Bulgaria	5.9	7.3	0.1	7.2	0.5	6.4	1.6	6.5	13.7	8.8	83.0%
62	2020	Int. Homocline-Central Arch	Mid-East	Saudi Arabia (C)	4.9	9.9	0.3	6.9	0.8	5.1	1.7	6.0	15.0	8.5	83.2%
63	1209	Angara-Lena Terrace	CIS	Russia (C)	0.0	8.1	0.1	1.5	7.0	0.0	7.0	7.1	8.1	8.5	83.4%
64	5045	Bend Arch-Fort Worth B.	N. America	USA (SC)	4.9	11.7	0.8	7.7	0.5	1.8	0.8	6.2	13.5	8.5	83.6%
65	5301	Tampico-Misantla Basin	N. America	Mexico (E)	6.9	6.7	0.1	8.1	0.2	1.0	0.3	7.2	7.7	8.4	83.8%
66	5244	Williston Basin	N. America	Canada	3.6	18.2	0.1	6.7	0.0	10.0	1.7	3.7	28.2	8.4	84.0%
67	5022	San Juan Basin	N. America	USA (SW)	0.3	38.2	1.4	8.1	0.0	1.8	0.3	1.7	40.0	8.4	84.2%

68	6055	Neuquen Basin	S. America	Argentina	2.4	20.7	0.3	6.2	1.2	4.5	2.0	3.9	25.2	8.1	84.4%
69	3142	Sichuan Basin	E. Asia	China	0.1	10.8	0.1	2.0	1.0	30.0	6.0	1.2	40.8	8.0	84.6%
70	8042	Indus	S. Asia	Pakistan, India	0.2	19.6	0.1	3.6	0.2	25.0	4.4	0.5	44.6	7.9	84.8%
71	2016	Fahud Salt Basin	Mid-East	Oman	4.5	10.0	0.2	6.4	0.7	5.1	1.6	5.4	15.1	7.9	85.0%
72	4060	Po/Adriatic Basin	Europe	Italy	0.4	18.9	0.1	3.7	1.3	16.2	4.0	1.8	35.1	7.7	85.2%
73	3822	North Sumatra Basin	SE Asia	Indonesia	0.7	25.6	0.9	5.9	0.2	8.0	1.5	1.8	33.6	7.4	85.4%
74	2048	Pelagian Basin	Mid-East	Libya/Tunisia	2.2	17.2	0.1	5.2	0.3	11.5	2.2	2.6	28.7	7.4	85.5%
75	3503	Mekong/Vung Tau Basin	SE Asia	Vietnam	0.9	1.3	0.1	1.2	4.4	9.0	5.9	5.4	10.3	7.1	85.7%
76	2014	Ghaba Salt Basin	Mid-East	Oman	1.4	19.0	0.5	5.1	0.2	9.8	1.8	2.1	28.8	6.9	85.9%
77	6059	Magallenes Basin	S. America	Chile/Argentina	1.2	24.8	0.2	5.5	0.3	6.6	1.4	1.7	31.4	6.9	86.0%
78	3805	Bintuni/Sulawati Province	SE Asia	Indonesia	0.5	9.5	0.1	2.2	1.3	20.3	4.7	1.9	29.8	6.9	86.2%
79	3930	Gippsland Basin	Australasia	Australia (SE)	3.9	9.8	0.7	6.2	0.3	0.5	0.4	4.9	10.3	6.6	86.4%
80	7146	Sud	Africa	Sudan	1.4	0.1	0.0	1.4	2.1	18.0	5.1	3.5	18.1	6.5	86.5%
81	3966	N. Guinea Foreland/Foldbelt	Australasia	New Guinea	0.4	11.0	0.1	2.3	0.0	25.0	4.2	0.5	36.0	6.5	86.7%
82	5037	SW Wyoming	N. America	USA (WC)	0.8	16.3	0.4	3.9	0.1	14.0	2.5	1.3	30.3	6.4	86.8%
83	5013	Ventura Basin	N. America	USA (SW)	3.4	5.8	0.2	4.6	0.9	4.6	1.7	4.5	10.4	6.3	87.0%
84	3507	Thai Basin	SE Asia	Thailand	0.2	8.9	0.3	2.0	0.9	20.0	4.2	1.4	28.9	6.2	87.1%
85	4057	Transylvania	Europe	Romania	0.1	30.7	0.0	5.2	0.0	5.4	0.9	0.1	36.1	6.1	87.3%
86	6058	San Jorge/Malvinas Basin	S. America	Argentina	3.3	3.6	0.1	4.0	1.2	5.3	2.0	4.6	8.9	6.0	87.4%
87	1210	Nepa-Botuoba Arch	CIS	Russia (EC)	2.0	22.0	0.3	6.0	0.0	0.0	0.0	2.3	22.0	6.0	87.6%
88	3128	Ordos Basin	E. Asia	China	0.7	5.6	0.0	1.6	0.5	23.0	4.3	1.2	28.6	6.0	87.7%
89	2004	Ma 'Rib-Al Jawf Basin	Mid-East	Yemen	1.2	16.6	0.3	4.3	0.2	8.5	1.6	1.7	25.1	5.9	87.9%
90	6103	Tobago Trough	S. America	Trinidad	0.1	22.6	0.1	4.0	0.0	10.0	1.7	0.2	32.6	5.6	88.0%
91	3825	Penyu/West Natuna Basin	SE Asia	Malaysia	0.6	5.7	0.1	1.7	1.2	16.5	4.0	1.9	22.2	5.6	88.1%
92	5033	Powder River Basin	N. America	USA (NC)	2.8	2.6	0.2	3.4	1.8	2.2	2.1	4.8	4.8	5.6	88.3%
93	6090	Middle Magdalena	S. America	Colombia	2.4	5.0	0.1	3.3	1.5	3.9	2.2	4.0	8.9	5.5	88.4%
94	8048	Irrawaddy	SE Asia	Myanmar	0.7	10.3	0.1	2.5	0.9	11.0	2.7	1.7	21.3	5.3	88.5%
95	3824	Northwest Java Basin	SE Asia	Indonesia	3.2	8.1	0.2	4.8	0.4	0.5	0.5	3.8	8.6	5.2	88.7%
96	4048	Pannonian Basin	Europe	Hungary	2.2	13.8	0.1	4.6	0.2	2.0	0.5	2.5	15.8	5.1	88.8%
97	3828	South Sumatra Basin	SE Asia	Indonesia	2.4	10.7	0.1	4.3	0.4	2.0	0.7	2.9	12.7	5.0	88.9%
98	3913	Browse Basin	Australasia	Australia	0.1	18.0	0.2	3.3	0.2	8.0	1.5	0.5	26.0	4.8	89.0%
99	1159	Fergana Basin	CIS	Kazakhstan (E)	0.8	1.5	0.1	1.2	3.0	3.0	3.5	3.9	4.5	4.7	89.1%
100	1150	North Ustyurt Basin	CIS	Kazakhstan	2.4	2.4	0.1	2.9	1.5	1.0	1.7	4.0	3.4	4.6	89.2%
101	4047	North Carpathian Basin	Europe	Ukraine	0.9	16.3	0.1	3.7	0.0	5.0	0.8	1.0	21.3	4.6	89.3%
102	6045	Santa Cruz-Tarija Basin	S. America	Bolivia/Paraguay	0.3	18.8	0.6	4.0	0.0	2.4	0.4	0.9	21.2	4.5	89.5%

103	5064	Illinois Basin	N. America	USA (EC)	3.9	0.1	0.0	3.9	0.4	0.6	0.5	4.3	0.7	4.4	89.6%
104	3910	Bonaparte Gulf Basin	Australasia	Australia	0.5	13.3	0.4	3.1	0.8	2.0	1.1	1.7	15.3	4.3	89.7%
105	5061	Southern Oklahoma	N. America	USA (C)	3.1	2.7	0.2	3.8	0.2	1.0	0.4	3.5	3.7	4.1	89.8%
106	8034	Assam	S. Asia	India	2.5	6.5	0.1	3.7	0.1	1.0	0.3	2.7	7.5	4.0	89.9%
107	5063	Michigan Basin	N. America	USA (NC)	1.1	3.9	0.2	2.0	0.9	6.5	2.0	2.2	10.4	3.9	90.0%
108	5062	Arkoma Basin	N. America	USA (C)	0.9	15.6	0.1	3.6	0.0	1.8	0.3	1.0	17.4	3.9	90.0%
109	5036	Wyoming Thrust Belt	N. America	USA (WC)	0.2	4.0	0.7	1.6	0.6	10.5	2.3	1.5	14.5	3.9	90.1%
110	1175	Yenisey-Khatanga Basin	CIS	Russia	0.1	14.2	0.1	2.6	0.5	5.0	1.3	0.7	19.2	3.9	90.2%
111	5003	Southern Alaska	N. America	USA (NW)	1.3	7.5	0.1	2.7	0.8	2.0	1.2	2.2	9.5	3.8	90.3%
112	2039	North Egypt Basin	Mid-East	Egypt	0.7	4.2	0.2	1.6	0.1	12.5	2.2	1.0	16.7	3.8	90.4%
113	1108	Azov-Kuban Basin	CIS	Russia (SW)	0.5	18.6	0.1	3.7	0.0	0.0	0.0	0.6	18.6	3.7	90.5%
114	5055	Nemaha Uplift	N. America	USA (C)	2.7	2.8	0.3	3.5	0.1	0.4	0.2	3.1	3.2	3.7	90.6%
115	6043	Madre dos Dios Basin	S. America	Peru, Bolivia, Brazil	0.1	10.8	0.7	2.6	0.3	3.8	0.9	1.1	14.6	3.5	90.7%
116	5034	Big Horn Basin	N. America	USA (NC)	2.7	1.8	0.1	3.1	0.3	0.4	0.4	3.1	2.2	3.5	90.8%
117	5031	Williston Basin (US)	N. America	USA (NC)	2.1	2.4	0.2	2.7	0.6	0.6	0.7	2.9	3.0	3.4	90.9%
118	4033	German-Polish Basin	Europe	Germany, Poland	0.1	13.7	0.1	2.5	0.1	5.0	0.9	0.3	18.7	3.4	90.9%
119	5053	Cambridge Arch-C. KS Uplift	N. America	USA (C)	2.9	0.6	0.1	3.1	0.2	0.3	0.2	3.2	0.9	3.3	91.0%
120	4019	Faeroes-Shetland-Orkney B.	Europe	UK	1.3	2.0	0.1	1.7	1.6	0.0	1.6	3.0	2.0	3.3	91.1%
121	6081	Talara Basin	S. America	Peru	1.7	2.9	0.0	2.2	1.1	0.0	1.1	2.8	2.9	3.3	91.2%
122	3159	Yingehai	E. Asia	China, Vietnam	0.0	8.4	0.1	1.5	0.0	10.0	1.7	0.1	18.4	3.2	91.2%
123	8047	Ganges-Brahmaputra Delta	S. Asia	Bengaladesh	0.1	14.3	0.1	2.6	0.5	0.0	0.5	0.7	14.3	3.1	91.3%
124	5020	Uinta-Piceance Basin	N. America	USA (WC)	1.6	4.7	0.1	2.5	0.2	2.0	0.5	1.9	6.7	3.0	91.4%
125	5245	Rocky Mtn Deformed Belt	N. America	USA (WC)	0.2	13.8	0.4	2.9	0.0	0.0	0.0	0.6	13.8	2.9	91.5%
126	8025	Sulaiman-Kirthar	S. Asia	Pakistan	0.1	15.8	0.1	2.8	0.0	0.0	0.0	0.2	15.8	2.8	91.5%
127	2012	East Flank Oman Sub-B.	Mid-East	Oman	2.4	0.1	0.0	2.4	0.4	0.1	0.4	2.8	0.2	2.8	91.6%
128	3605	Palawan Shelf	SE Asia	Philippines	0.2	5.6	0.2	1.3	1.5	0.0	1.5	1.9	5.6	2.8	91.7%
129	5304	Saline-Comalcalco Basin	N. America	Mexico (SE)	2.4	2.2	0.0	2.8	0.0	0.0	0.0	2.4	2.2	2.8	91.7%
130	2011	South Oman Salt Basin	Mid-East	Oman	2.2	0.5	0.1	2.4	0.3	0.3	0.4	2.6	0.8	2.7	91.8%
131	5060	Cherokee Platform	N. America	USA (C)	2.1	1.4	0.1	2.4	0.1	0.2	0.1	2.3	1.6	2.6	91.9%
132	4044	Pyrenean Foothills-Ebro B.	Europe	Spain, France	0.1	12.6	0.1	2.3	0.0	0.0	0.0	0.2	12.6	2.3	91.9%
133	5039	Denver Basin	N. America	USA (WC)	0.9	3.5	0.3	1.8	0.2	1.5	0.5	1.4	5.0	2.3	92.0%
134	5009	Sacramento Basin	N. America	USA (W)	0.1	9.2	0.1	1.7	0.0	2.8	0.5	0.2	12.0	2.2	92.0%
135	3809	East Java Basin	SE Asia	Indonesia	0.4	7.6	0.1	1.8	0.1	2.0	0.4	0.6	9.6	2.2	92.1%
136	5012	Santa Maria Basin	N. America	USA (SW)	1.5	1.5	0.1	1.9	0.2	0.6	0.3	1.8	2.1	2.1	92.1%
137	4030	Irish Sea	Europe	UK	0.2	9.6	0.1	1.9	0.0	0.5	0.1	0.3	10.1	2.0	92.2%

138	2038	Abu Gharadiq Basin	Mid-East	Egypt	0.5	3.9	0.2	1.4	0.1	3.0	0.6	0.8	6.9	2.0	92.2%
139	1156	Afghan-Tajik Basin	CIS	Afghanistan/Tajikistan	0.1	7.5	0.1	1.5	0.3	1.0	0.5	0.5	8.5	1.9	92.3%
140	3924	Eromanga	Australasia	Australia	0.3	8.5	0.1	1.8	0.1	0.0	0.1	0.5	8.5	1.9	92.3%
141	3031	Taranaki Basin	Australasia	New Zealand	0.2	7.2	0.2	1.6	0.1	0.6	0.2	0.5	7.8	1.8	92.4%
142	4015	Hammerfest-Varanger B.	Europe	Norway	0.1	8.4	0.1	1.6	0.1	0.0	0.1	0.3	8.4	1.7	92.4%
143	2089	Anah Graben	Mid-East	Turkey	1.2	1.2	0.1	1.5	0.2	0.0	0.2	1.5	1.2	1.7	92.4%
144	2074	Khleisha Uplift	Mid-East	Iraq/Syria	1.2	0.8	0.1	1.4	0.2	0.0	0.2	1.5	0.8	1.6	92.5%
145	2075	Euphrates/Mardin	Mid-East	Iraq	1.0	1.8	0.1	1.4	0.2	0.0	0.2	1.3	1.8	1.6	92.5%
146	4046	Bohemia	Europe	Czech, Germany	0.9	3.3	0.1	1.6	0.0	0.0	0.0	1.0	3.3	1.6	92.6%
147	5035	Wind River Basin	N. America	USA (NC)	0.5	2.8	0.1	1.1	0.1	1.5	0.4	0.7	4.3	1.5	92.6%
148	4051	Alps	Europe	Austria, Italy	0.3	6.2	0.1	1.4	0.0	0.0	0.0	0.4	6.2	1.4	92.6%
149	3505	Saigon	SE Asia	Vietnam	0.2	6.0	0.2	1.4	0.0	0.0	0.0	0.4	6.0	1.4	92.7%
150	6051	Cuyo Basin	S. America	Argentina	1.3	0.3	0.0	1.4	0.0	0.0	0.0	1.3	0.3	1.4	92.7%
151	5059	Sedgwick Basin	N. America	USA (C)	0.9	2.2	0.1	1.4	0.0	0.0	0.0	1.0	2.2	1.4	92.7%
152	1059	Ludlov Saddle	CIS	Russia (W)	0.0	8.1	0.0	1.4	0.0	0.0	0.0	0.0	8.1	1.4	92.8%
153	2045	Murzak	Mid-East	Libya	1.1	0.0	0.0	1.1	0.2	0.0	0.2	1.3	0.0	1.3	92.8%
154	5306	Macuspana Basin	N. America	Mexico (SE)	0.1	5.9	0.2	1.3	0.0	0.0	0.0	0.3	5.9	1.3	92.8%
155	6092	E. Cordillera Basin	S. America	Colombia	0.1	5.0	0.3	1.2	0.0	0.0	0.0	0.4	5.0	1.2	92.9%
		TOTAL 155 Basins			1587	6629	112	2804	402	3870	1047	2101	10500	3850	92.9%
		TOTAL WORLD			1608	6753	112	2845	475	4955	1301	2196	11708	4147	100%

* Excluding coalbed methane

1B:
Worldwide Depleted Oil Field/EOR Potential

Depleted Oil Field (EOR) Sequestration Potential

Data Sources:

Masters 1998, *World Conventional Crude Oil & Natural Gas*
Klett 1997, *Ranking of the World's Oil and Gas Provinces*
Oil and Gas Journal 1998, *Worldwide Production*
Numerous other basin studies.
[1] Gottlicher and Pruschek, 1996
[2] Oil volume discounted at 10% ROI
3 World price, gravity adj $0.1/API,less 20% government taxes
4 Miscible EOR % of OOIP from Permian B. relationship
estimated 20% of OOIP in non-waterflooded reservoirs.

Capital Costs			**Operating Costs**			**Enhanced Oil Recovery**[4]	
Field Well Costs (Shallow)	$0.80	per BO	O & M (Shallow)	$2.70	/BO	Miscible Recovery:API Grav	
Medium (1500 m)	$1.20	per BO	Medium	$3.38	/BO	Immiscible Rec : API Grav	
Deep	$1.60	per BO	Deep	$4.05	/BO	Primary + Secondary	50%
Offshore Factor	3.0	times	Offshore Factor	1.5	times	(of OOIP @ 35 API)	
CO_2 Pipeline Costs (Near)	$0.20	per BO	CO_2 Supply Costs (Natural)	$0.65	/Mcf	Net CO_2/EOR Misc	6.0
Medium (<100 km)	$1.00	per BO	Gas Plant	$1.00	/Mcf	Net CO2/EOR Immsc	10.0
Far (100-500 km)	$3.00	per BO	Power Plant[1]	$0.65	/Mcf	World Oil Price	$15
Offshore Factor	2.0	times	Offshore Factor	1.0	times	($/BO 40-deg API)	

4. Reservoir Province			**5. Reservoir Attributes**				**6.Miscibility**		**7. Estimated EOR Costs**					**8. Profits**[2]		**9. EOR**		**10. Sequestration Potential**				
Rank Sqstr (Gt)	**Rank O&G (BOE)**	**Province Name**	**On/ Off Shore**	**Anthro. CO_2 Supply**	**Avg. Depth (m)**	**Oil Gravity (API)**	**Miscb EOR**	**Immis EOR**	**Field Cap ($/BO)**	**CO_2 Pipe ($/BO)**	**O&M Oper. ($/BO)**	**CO_2 Supply ($/BO)**	**Total Costs ($/BO)**	**Net Oil Price**[3] **($/BO)**	**Profit (Loss) ($/BO)**	**OOIP (BBO)**	**EOR (BBO)**	**CO_2/ EOR (Mcf/BO)**	**CO_2 Sqstr Potential (Tcf)**	**(Gt)**	**Sqstr Costs ($/t)**	**Total Costs G $**
1	2	Mesopotar	On	Med	2500	30	75%	0%	0.80	1.00	2.70	3.90	8.40	11.20	2.80	728	36.4	6.00	218.4	11.6	-8.8	-102
2	1	West Sibe	On	Far	1700	25	25%	50%	0.80	3.00	2.70	5.63	12.13	10.80	-1.33	459	22.9	8.67	198.8	10.5	2.9	31
3	4	Greater Gl	On	Med	2109.756	34	75%	0%	0.80	1.00	2.70	3.90	8.40	11.52	3.12	332	26.3	6.00	157.8	8.3	-9.8	-82
4	5	Rub Al Kh	On	Med	2500	35	75%	0%	0.80	1.00	2.70	3.90	8.40	11.60	3.20	200	18.1	6.00	108.8	5.8	-10.1	-58
5	8	North Sea	Off	Med	3500	40	75%	0%	3.60	2.00	5.06	3.90	14.56	12.00	-2.56	98	16.6	6.00	99.3	5.3	8.1	42
6	12	Villahermo	On/Off	Near	4300	40	75%	0%	3.60	0.30	4.56	3.90	12.36	12.00	-0.36	97	16.4	6.00	98.2	5.2	1.1	6
7	3	Zagros Fo	On	Med	3000	30	75%	0%	1.20	1.00	3.38	3.90	9.48	11.20	1.73	304	15.2	6.00	91.2	4.8	-5.4	-26
8	10	Volga-Ura	On	Near	1700	25	25%	50%	0.80	0.20	2.70	5.63	9.33	10.80	1.47	169	8.5	8.67	73.2	3.9	-3.2	-12
9	11	Niger Delt	On/Off	Near	3000	40	75%	0%	2.70	0.30	3.80	3.90	10.70	12.00	1.30	71	12.0	6.00	72.1	3.8	-4.1	-16
10	18	Sirte Basi	On	Far	2500	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	71	12.0	6.00	71.8	3.8	-5.0	-19
11	13	Maracaibo	On/Off	Near	2500	25	25%	50%	1.80	0.30	3.04	5.63	10.77	10.80	0.03	143	7.2	8.67	62.0	3.3	-0.1	0
12	14	East Vene	On/Off	Near	3000	20	25%	50%	2.70	0.30	3.80	5.63	12.43	10.40	-2.03	118	5.9	8.67	51.2	2.7	4.4	12
13	9	Western G	On	Near	2200	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	91	8.3	6.00	49.8	2.6	-12.6	-33
14	15	Permian B	On	Near	2800	35	75%	0%	1.20	0.20	3.38	3.90	8.68	11.60	2.93	77	7.0	6.00	41.8	2.2	-9.2	-20
15	21	S. Caspian	Off	Med	3000	40	75%	0%	3.60	2.00	5.06	3.90	14.56	12.00	-2.56	40	6.7	6.00	40.4	2.1	8.1	17
16	27	West-Cent	Off	Far	3000	40	75%	0%	3.60	6.00	5.06	3.90	18.56	12.00	-6.56	33	5.5	6.00	33.1	1.8	20.7	36
17	7	North Cas	On/Off	Near	3000	30	75%	0%	2.70	0.30	3.80	3.90	10.70	11.20	0.50	107	5.3	6.00	32.0	1.7	-1.6	-3
18	28	Trias/Ghad	On	Far	3000	48	75%	0%	1.20	3.00	3.38	3.90	11.48	12.64	1.17	26	5.3	6.00	31.8	1.7	-3.7	-6
19	23	Bohaiwan	On/Off	Near	2000	25	25%	50%	1.80	0.30	3.04	5.63	10.77	10.80	0.03	73	3.7	8.67	31.6	1.7	-0.1	0
20	17	Alberta Ba	On	Near	2000	36	75%	0%	0.80	0.20	2.70	3.90	7.60	11.68	4.08	41	4.2	6.00	25.3	1.3	-12.9	-17
21	37	San Joaqu	On	Near	1200	20	0%	75%	0.80	0.20	2.70	6.50	10.20	10.40	0.20	47	2.3	10.00	23.5	1.2	-0.4	0
22	22	N. Alaska	On	Far	2000	25	25%	50%	0.80	3.00	2.70	5.63	12.13	10.80	-1.33	51	2.6	8.67	22.2	1.2	2.9	3
23	19	Gulf Ceno	Off	Med	2300	40	75%	0%	0.80	2.00	4.05	3.90	10.75	12.00	1.25	20	3.4	6.00	20.5	1.1	-3.9	-4
24	38	Tarim Bas	On	Far	3000	40	75%	0%	1.20	3.00	3.38	3.90	11.48	12.00	0.52	20	3.4	6.00	20.1	1.1	-1.7	-2
25	24	Timan-Pec	On	Far	2000	25	25%	50%	0.80	3.00	2.70	5.63	12.13	10.80	-1.33	45	2.2	8.67	19.4	1.0	2.9	3
26	55	Jungger B	On	Far	3000	40	75%	0%	1.20	3.00	3.38	3.90	11.48	12.00	0.52	16	2.8	6.00	16.6	0.9	-1.7	-1
27	6	Qatar Arch	On/Off	Near	2100	35	75%	0%	1.80	0.30	3.04	3.90	9.04	11.60	2.56	29	2.6	6.00	15.5	0.8	-8.1	-7
28	49	Red Sea B	Off	Far	2300	38	75%	0%	2.40	6.00	4.05	3.90	16.35	11.84	-4.51	19	2.5	6.00	15.2	0.8	14.2	11
29	31	Middle Ca	On/Off	Med	2500	35	75%	0%	1.80	1.50	3.04	3.90	10.24	11.60	1.36	25	2.2	6.00	13.5	0.7	-4.3	-3
30	48	Bombay B	Off	Med	1800	38	75%	0%	2.40	2.00	4.05	3.90	12.35	11.84	-0.51	17	2.2	6.00	13.2	0.7	1.6	1
31	30	Widyan Ba	On	Med	3000	30	75%	0%	1.20	1.00	3.38	3.90	9.48	11.20	1.73	43	2.2	6.00	13.0	0.7	-5.4	-4
32	61	Carpathian	On	Near	3500	42	75%	0%	1.20	0.20	3.38	3.90	8.68	12.16	3.49	10	2.1	6.00	12.4	0.7	-11.0	-7
33	32	East Texas	On	Near	2300	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	23	2.0	6.00	12.3	0.7	-12.6	-8
34	63	Angara-Le	On	Med	2500	40	75%	0%	0.80	1.00	2.70	3.90	8.40	12.00	3.60	12	2.0	6.00	12.0	0.6	-11.3	-7
35	34	Songliao B	On	Near	2500	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	38	1.9	6.00	11.3	0.6	-11.3	-7
36	42	Malay Bas	Off	Far	1800	46	75%	0%	2.40	6.00	4.05	3.90	16.35	12.48	-3.87	9	1.8	6.00	10.6	0.6	12.2	7
37	39	Campos B	Off	Med	3900	29	75%	0%	4.80	2.00	6.08	3.90	16.78	11.12	-5.66	35	1.8	6.00	10.5	0.6	17.8	10
38	25	Grand Erg	On	Far	3000	45	75%	0%	1.20	3.00	3.38	3.90	11.48	12.40	0.92	8	1.7	6.00	10.1	0.5	-2.9	-2

39	35	Louisiana-	On	Near	2500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	18	1.6	6.00	9.8	0.5	-12.6	-7
40	41	Central Su	On	Med	1200	30	75%	0%	0.80	1.00	2.70	3.90	8.40	11.20	2.80	32	1.6	6.00	9.6	0.5	-8.8	-5
41	50	Illizi Basin	On	Far	3000	45	75%	0%	1.20	3.00	3.38	3.90	11.48	12.40	0.92	8	1.6	6.00	9.4	0.5	-2.9	-1
42	52	Putamayo-	On	Far	2900	28	50%	25%	1.20	3.00	3.38	4.77	12.34	11.04	-1.30	25	1.3	7.33	9.3	0.5	3.4	2
43	54	Vestford-H	Off	Far	3000	42	75%	0%	3.60	6.00	5.06	3.90	18.56	12.16	-6.40	8	1.5	6.00	9.2	0.5	20.2	10
44	40	Baram Del	On/Off	Far	2500	35	75%	0%	1.80	4.50	3.04	3.90	13.24	11.60	-1.64	16	1.5	6.00	8.9	0.5	5.2	2
45	16	Amu-Darya	On	Far	2500	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	8	1.4	6.00	8.4	0.4	-5.0	-2
46	57	North Sakl	On/Off	Far	2200	40	75%	0%	1.80	4.50	3.04	3.90	13.24	12.00	-1.24	8	1.4	6.00	8.3	0.4	3.9	2
47	79	Gippsland	Off	Med	1500	40	75%	0%	2.40	2.00	4.05	3.90	12.35	12.00	-0.35	8	1.4	6.00	8.3	0.4	1.1	0
48	58	Llanos Bas	On	Med	3200	35	75%	0%	1.20	1.00	3.38	3.90	9.48	11.60	2.13	14	1.3	6.00	7.8	0.4	-6.7	-3
49	65	Tampico-M	On/Off	Med	3200	35	75%	0%	2.70	1.50	3.80	3.90	11.90	11.60	-0.30	13	1.2	6.00	7.3	0.4	0.9	0
50	92	Powder Ri	On	Near	1300	20	0%	75%	0.80	0.20	2.70	6.50	10.20	10.40	0.20	14	0.7	10.00	7.1	0.4	-0.4	0
51	47	Reconcave	On/Off	Far	3900	29	75%	0%	3.60	4.50	4.56	3.90	16.56	11.12	-5.44	24	1.2	6.00	7.1	0.4	17.1	6
52	56	Los Angele	On	Near	1500	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	21	1.1	6.00	6.4	0.3	-11.3	-4
53	64	Bend Arch	On	Near	2500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	12	1.1	6.00	6.3	0.3	-12.6	-4
54	62	Interior Ho	On	Med	2500	35	75%	0%	0.80	1.00	2.70	3.90	8.40	11.60	3.20	11	1.0	6.00	6.1	0.3	-10.1	-3
55	100	North Usty	On	Med	1000	20	0%	75%	0.80	1.00	2.70	6.50	11.00	10.40	-0.60	12	0.6	10.00	6.0	0.3	1.1	0
56	45	Kutei Basi	On/Off	Far	2500	35	75%	0%	1.80	4.50	3.04	3.90	13.24	11.60	-1.64	11	1.0	6.00	5.7	0.3	5.2	2
57	46	South Bare	Off	Far	3000	45	75%	0%	3.60	6.00	5.06	3.90	18.56	12.40	-6.16	5	0.9	6.00	5.6	0.3	19.4	6
58	29	Anadarko	On	Near	2500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	10	0.9	6.00	5.5	0.3	-12.6	-4
59	51	Northwest	Off	Far	1800	42	75%	0%	2.40	6.00	4.05	3.90	16.35	12.16	-4.19	4	0.9	6.00	5.4	0.3	13.2	4
60	116	Big Horn E	On	Med	3000	40	75%	0%	1.20	1.00	3.38	3.90	9.48	12.00	2.53	5	0.9	6.00	5.3	0.3	-8.0	-2
61	120	Faeroes-S	Off	Far	3000	40	75%	0%	3.60	6.00	5.06	3.90	18.56	12.00	-6.56	5	0.8	6.00	5.1	0.3	20.7	6
62	75	Mekong/V	Off/On	Med	2500	34	75%	0%	1.80	1.50	3.04	3.90	10.24	11.52	1.28	10	0.8	6.00	4.9	0.3	-4.0	-1
63	83	Ventura Ba	On	Near	1600	25	25%	50%	0.80	0.20	2.70	5.63	9.33	10.80	1.47	11	0.6	8.67	4.9	0.3	-3.2	-1
64	97	South Sum	On	Near	1200	40	75%	0%	0.80	0.20	2.70	3.90	7.60	12.00	4.40	5	0.8	6.00	4.9	0.3	-13.9	-4
65	80	Sud	On	Far	1900	38	75%	0%	0.80	3.00	2.70	3.90	10.40	11.84	1.44	6	0.8	6.00	4.9	0.3	-4.5	-1
66	71	Fahud Salt	On	Far	800	32	50%	25%	0.80	3.00	2.70	4.77	11.27	11.36	0.09	11	0.7	7.33	4.8	0.3	-0.2	0
67	95	Northwest	Off/On	Med	2000	37	75%	0%	1.80	1.50	3.04	3.90	10.24	11.76	1.52	7	0.8	6.00	4.8	0.3	-4.8	-1
68	103	Illinois Bas	On	Near	1500	25	25%	50%	0.80	0.20	2.70	5.63	9.33	10.80	1.47	11	0.5	8.67	4.7	0.2	-3.2	-1
69	130	South Oma	On	Far	1200	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	4	0.7	6.00	4.4	0.2	-5.0	-1
70	96	Pannonian	On	Near	2000	40	75%	0%	0.80	0.20	2.70	3.90	7.60	12.00	4.40	4	0.7	6.00	4.2	0.2	-13.9	-3
71	53	Palo Duro	On	Near	1800	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	8	0.7	6.00	4.1	0.2	-12.6	-3
72	99	Fergana B	On	Far	2000	35	75%	0%	0.80	3.00	2.70	3.90	10.40	11.60	1.20	7	0.7	6.00	4.0	0.2	-3.8	-1
73	127	East Flank	On	Far	1200	38	75%	0%	0.80	3.00	2.70	3.90	10.40	11.84	1.44	5	0.6	6.00	3.9	0.2	-4.5	-1
74	87	Nepa-Botu	On	Far	2500	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	4	0.6	6.00	3.9	0.2	-5.0	-1
75	111	Southern A	On/Off	Med	1200	40	75%	0%	1.80	1.50	3.04	3.90	10.24	12.00	1.76	4	0.6	6.00	3.8	0.2	-5.6	-1
76	66	Williston B	On	Near	1400	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	7	0.6	6.00	3.8	0.2	-12.6	-3
77	105	Southern C	On	Med	2500	35	75%	0%	0.80	1.00	2.70	3.90	8.40	11.60	3.20	7	0.6	6.00	3.6	0.2	-10.1	-2
78	129	Saline-Cor	On/Off	Med	4000	38	75%	0%	3.60	1.50	4.56	3.90	13.56	11.84	-1.72	4	0.6	6.00	3.3	0.2	5.4	1
79	91	Penyu/Wes	Off	Far	3000	40	75%	0%	3.60	6.00	5.06	3.90	18.56	12.00	-6.56	3	0.5	6.00	3.2	0.2	20.7	4
80	107	Michigan	On	Near	2000	38	75%	0%	0.80	0.20	2.70	3.90	7.60	11.84	4.24	4	0.5	6.00	3.1	0.2	-13.4	-2
81	104	Bonaparte	Off	Far	2000	45	75%	0%	2.40	6.00	4.05	3.90	16.35	12.40	-3.95	3	0.5	6.00	3.1	0.2	12.4	2
82	89	Ma 'Rib-Al	On	Far	2000	45	75%	0%	0.80	3.00	2.70	3.90	10.40	12.40	2.00	3	0.5	6.00	3.1	0.2	-6.3	-1
83	117	Williston B	On	Near	2000	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	5	0.5	6.00	3.0	0.2	-12.6	-2
84	86	San Jorge	On/Off	Far	2500	30	75%	0%	1.80	4.50	3.04	3.90	13.24	11.20	-2.04	10	0.5	6.00	2.9	0.2	6.4	1
85	33	Greater Sa	On/Off	Far	1300	39	75%	0%	1.80	4.50	3.04	3.90	13.24	11.92	-1.32	3	0.5	6.00	2.9	0.2	4.2	1
86	121	Talara Bas	On/Off	Med	1700	35	75%	0%	1.80	1.50	3.04	3.90	10.24	11.60	1.36	5	0.5	6.00	2.9	0.2	-4.3	-1
87	68	Neuquen	On	Med	3000	32	75%	0%	1.20	1.00	3.38	3.90	9.48	11.36	1.89	8	0.5	6.00	2.8	0.2	-5.9	-1
88	143	Anah Grab	On	Med	1500	15	0%	75%	0.80	1.00	2.70	6.50	11.00	10.00	-1.00	6	0.3	10.00	2.8	0.1	1.9	0
89	77	Magallene	On/Off	Far	1900	40	75%	0%	1.80	4.50	3.04	3.90	13.24	12.00	-1.24	3	0.5	6.00	2.8	0.1	3.9	1
90	60	Labrador-N	Off	Far	2100	40	75%	0%	2.40	6.00	4.05	3.90	16.35	12.00	-4.35	3	0.5	6.00	2.7	0.1	13.7	2
91	73	North Sum	On	Med	3000	55	75%	0%	1.20	1.00	3.38	3.90	9.48	13.20	3.73	2	0.5	6.00	2.7	0.1	-11.7	-2
92	72	Po/Adriatic	On/Off	Near	3000	20	0%	75%	2.70	0.30	3.80	6.50	13.30	10.40	-2.90	5	0.3	10.00	2.7	0.1	5.5	1

93	74	Pelagian E	Off	Far	2500	35	75%	0%	2.40	6.00	4.05	3.90	16.35	11.60	-4.75	5	0.4	6.00	2.7	0.1	15.0	2
94	93	Middle Ma	On	Med	2200	30	75%	0%	0.80	1.00	2.70	3.90	8.40	11.20	2.80	9	0.4	6.00	2.6	0.1	-8.8	-1
95	43	Dnieper-D	On	Near	2500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	5	0.4	6.00	2.6	0.1	-12.6	-2
96	109	Wyoming T	On	Med	3000	40	75%	0%	1.20	1.00	3.38	3.90	9.48	12.00	2.53	2	0.4	6.00	2.5	0.1	-8.0	-1
97	82	SW Wyom	On	Near	3000	40	75%	0%	1.20	0.20	3.38	3.90	8.68	12.00	3.33	2	0.4	6.00	2.3	0.1	-10.5	-1
98	88	Ordos Bas	On	Med	1000	15	0%	75%	0.80	1.00	2.70	6.50	11.00	10.00	-1.00	5	0.2	10.00	2.3	0.1	1.9	0
99	84	Thai Basin	Off	Med	2000	50	75%	0%	2.40	2.00	4.05	3.90	12.35	12.80	0.45	2	0.4	6.00	2.2	0.1	-1.4	0
100	106	Assam	On	Far	3500	33	75%	0%	1.20	3.00	3.38	3.90	11.48	11.44	-0.04	5	0.4	6.00	2.2	0.1	0.1	0
101	153	Murzak	On	Far	2500	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	2	0.4	6.00	2.2	0.1	-5.0	-1
102	119	Cambridge	On	Near	2000	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	7	0.3	6.00	2.0	0.1	-11.3	-1
103	136	Santa Mar	On	Near	1500	23	25%	50%	0.80	0.20	2.70	5.63	9.33	10.64	1.31	5	0.2	8.67	2.0	0.1	-2.9	0
104	69	Sichuan B	On	Near	3500	40	75%	0%	1.20	0.20	3.38	3.90	8.68	12.00	3.33	2	0.3	6.00	2.0	0.1	-10.5	-1
105	114	Nemaha U	On	Near	2500	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	7	0.3	6.00	2.0	0.1	-11.3	-1
106	144	Khleisha U	On	Far	2000	20	25%	50%	0.80	3.00	2.70	5.63	12.13	10.40	-1.73	5	0.2	8.67	2.0	0.1	3.8	0
107	78	Bintuni/Sul	Off	Far	1100	35	75%	0%	2.40	6.00	4.05	3.90	16.35	11.60	-4.75	4	0.3	6.00	1.9	0.1	15.0	2
108	128	Palawan S	Off	Far	3800	35	75%	0%	4.80	6.00	6.08	3.90	20.78	11.60	-9.18	4	0.3	6.00	1.9	0.1	28.9	3
109	94	Irrawaddy	On/Off	Far	1500	36	75%	0%	1.80	4.50	3.04	3.90	13.24	11.68	-1.56	3	0.3	6.00	1.9	0.1	4.9	1
110	76	Ghaba Sal	On	Far	1100	34	75%	0%	0.80	3.00	2.70	3.90	10.40	11.52	1.12	4	0.3	6.00	1.9	0.1	-3.5	0
111	131	Cherokee	On	Near	2200	32	75%	0%	0.80	0.20	2.70	3.90	7.60	11.36	3.76	5	0.3	6.00	1.7	0.1	-11.8	-1
112	26	NW Germa	On/Off	Near	2500	30	75%	0%	1.80	0.30	3.04	3.90	9.04	11.20	2.16	5	0.3	6.00	1.5	0.1	-6.8	-1
113	102	Santa Cru	On	Far	3800	50	75%	0%	1.60	3.00	4.05	3.90	12.55	12.80	0.25	1	0.3	6.00	1.5	0.1	-0.8	0
114	145	Euphrates	On	Near	1500	36	75%	0%	0.80	0.20	2.70	3.90	7.60	11.68	4.08	2	0.2	6.00	1.5	0.1	-12.9	-1
115	133	Denver Ba	On	Near	1800	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	3	0.2	6.00	1.5	0.1	-12.6	-1
116	147	Wind Rive	On	Med	3000	40	75%	0%	1.20	1.00	3.38	3.90	9.48	12.00	2.53	1	0.2	6.00	1.3	0.1	-8.0	-1
117	124	Uinta-Pice	On	Med	1600	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	4	0.2	6.00	1.2	0.1	-11.3	-1
118	110	Yenisey-K	On	Far	2500	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	1	0.2	6.00	1.2	0.1	-5.0	0
119	115	Madre dos	On	Far	2500	35	75%	0%	0.80	3.00	2.70	3.90	10.40	11.60	1.20	2	0.2	6.00	1.1	0.1	-3.8	0
120	67	San Juan	On	Near	2000	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	4	0.2	6.00	1.1	0.1	-11.3	-1
121	108	Arkoma Ba	On	Med	2500	35	75%	0%	0.80	1.00	2.70	3.90	8.40	11.60	3.20	2	0.2	6.00	1.0	0.1	-10.1	-1
122	146	Bohemia	On	Near	1500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	2	0.2	6.00	1.0	0.1	-12.6	-1
123	112	North Egy	On/Off	Med	2000	35	75%	0%	1.80	1.50	3.04	3.90	10.24	11.60	1.36	2	0.2	6.00	1.0	0.1	-4.3	0
124	113	Azov-Kuba	On	Far	2300	40	75%	0%	0.80	3.00	2.70	3.90	10.40	12.00	1.60	1	0.2	6.00	1.0	0.1	-5.0	0
125	150	Cuyo Basi	On	Med	2000	32	75%	0%	0.80	1.00	2.70	3.90	8.40	11.36	2.96	3	0.2	6.00	1.0	0.1	-9.3	0
126	81	New Guine	On	Far	3000	44	75%	0%	1.20	3.00	3.38	3.90	11.48	12.32	0.84	1	0.2	6.00	0.9	0.0	-2.7	0
127	98	Browse Ba	Off	Far	2000	45	75%	0%	2.40	6.00	4.05	3.90	16.35	12.40	-3.95	1	0.2	6.00	0.9	0.0	12.4	1
128	140	Eromanga	On	Far	1600	43	75%	0%	0.80	3.00	2.70	3.90	10.40	12.24	1.84	1	0.1	6.00	0.9	0.0	-5.8	0
129	20	Mediterran	Off	Far	3000	40	75%	0%	3.60	6.00	5.06	3.90	18.56	12.00	-6.56	1	0.1	6.00	0.8	0.0	20.7	1
130	141	Taranaki E	Off	Med	3500	50	75%	0%	3.60	2.00	5.06	3.90	14.56	12.80	-1.76	1	0.1	6.00	0.8	0.0	5.6	0
131	151	Sedgwick	On	Near	2200	32	75%	0%	0.80	0.20	2.70	3.90	7.60	11.36	3.76	2	0.1	6.00	0.7	0.0	-11.8	0
132	123	Ganges-B	On/Off	Med	2000	35	75%	0%	1.80	1.50	3.04	3.90	10.24	11.60	1.36	1	0.1	6.00	0.7	0.0	-4.3	0
133	138	Abu Ghara	On	Med	3000	33	75%	0%	1.20	1.00	3.38	3.90	9.48	11.44	1.97	2	0.1	6.00	0.7	0.0	-6.2	0
134	101	North Carp	On	Near	2000	30	75%	0%	0.80	0.20	2.70	3.90	7.60	11.20	3.60	2	0.1	6.00	0.6	0.0	-11.3	0
135	125	Rocky Mou	On	Near	2500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	1	0.1	6.00	0.6	0.0	-12.6	0
136	44	Anglo-Dut	Off/On	Near	2000	28	50%	25%	1.80	0.30	3.04	4.77	9.90	11.04	1.14	2	0.1	7.33	0.6	0.0	-2.9	0
137	142	Hammerfe	Off	Far	3000	42	75%	0%	3.60	6.00	5.06	3.90	18.56	12.16	-6.40	0	0.1	6.00	0.6	0.0	20.2	1
138	139	Afghan-Ta	On	Far	3500	36	75%	0%	1.20	3.00	3.38	3.90	11.48	11.68	0.20	1	0.1	6.00	0.6	0.0	-0.6	0
139	70	Indus	Off	Med	3000	35	75%	0%	3.60	2.00	5.06	3.90	14.56	11.60	-2.96	1	0.1	6.00	0.5	0.0	9.3	0
140	137	Irish Sea	Off	Near	3000	40	75%	0%	3.60	2.00	5.06	3.90	14.56	12.00	-2.56	1	0.1	6.00	0.5	0.0	8.1	0
141	154	Macuspan	On/Off	Med	4300	40	75%	0%	3.60	1.50	4.56	3.90	13.56	12.00	-1.56	1	0.1	6.00	0.5	0.0	4.9	0
142	148	Alps	On	Near	2000	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	1	0.1	6.00	0.4	0.0	-12.6	0
143	149	Saigon	Off	Far	3000	35	75%	0%	3.60	6.00	5.06	3.90	18.56	11.60	-6.96	1	0.1	6.00	0.4	0.0	21.9	0
144	135	East Java	On/Off	Med	1200	30	75%	0%	1.80	1.50	3.04	3.90	10.24	11.20	0.96	1	0.1	6.00	0.4	0.0	-3.0	0
145	126	Sulaiman-	On	Med	2800	40	75%	0%	1.20	1.00	3.38	3.90	9.48	12.00	2.53	0	0.1	6.00	0.3	0.0	-8.0	0
146	134	Sacramen	On	Near	2200	40	75%	0%	0.80	0.20	2.70	3.90	7.60	12.00	4.40	0	0.1	6.00	0.3	0.0	-13.9	0

147	155	E. Cordille	On	Near	2500	28	50%	25%	0.80	0.20	2.70	4.77	8.47	11.04	2.57	1	0.0	7.33	0.3	0.0	-6.6	0
148	59	Burgos/Sa	On/Off	Med	3000	30	75%	0%	2.70	1.50	3.80	3.90	11.90	11.20	-0.70	1	0.1	6.00	0.3	0.0	2.2	0
149	118	German-P	On	Near	2000	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	1	0.1	6.00	0.3	0.0	-12.6	0
150	36	Lena-Vilyu	On	Med	3000	35	75%	0%	1.20	1.00	3.38	3.90	9.48	11.60	2.13	0	0.0	6.00	0.2	0.0	-6.7	0
151	90	Tobago Tr	Off	Med	3100	35	75%	0%	3.60	2.00	5.06	3.90	14.56	11.60	-2.96	0	0.0	6.00	0.2	0.0	9.3	0
152	132	Pyrenean	On	Near	1500	35	75%	0%	0.80	0.20	2.70	3.90	7.60	11.60	4.00	0	0.0	6.00	0.2	0.0	-12.6	0
153	122	Yingehai	Off	Far	3000	40	75%	0%	3.60	6.00	5.06	3.90	18.56	12.00	-6.56	0	0.0	6.00	0.2	0.0	20.7	0
154	85	Transylvan	On	Med	2000	35	75%	0%	0.80	1.00	2.70	3.90	8.40	11.60	3.20	0	0.0	6.00	0.1	0.0	-10.1	0
155	152	Ludlov Sad	Off	Med	2400	40	75%	0%	2.40	2.00	4.05	3.90	12.35	12.00	-0.35	0	0.0	6.00	0.0	0.0	1.1	0
		TOTAL 155 Basins														4351	341		2214	117	-2.5	-294
		TOTAL WORLD														4686	368		2385	126	-2.5	-316

1C:
Worldwide Depleted Natural Gas Field Potential

Depleted Natural Gas Field Sequestration Potential

Data Sources:

Masters 1998, *World Conventional Crude Oil & Natural Gas*
Klett 1997, *Ranking of the World's Oil and Gas Provinces*
Oil and Gas Journal 1998, *Worldwide Production*
Numerous other basin studies.
[1] Gottlicher and Pruschek, 1996
[2] Joint Association Survey, 1998
[3] Pressure gradient 0.433 psi/ft; temp gradient 1.5 deg F/100 ft.
[4] CH_4 and CO_2 compressibility factors accounted for.

Capital Costs[2]			Operating Costs			Gas Recovery	
Field Well Costs (Shallow)	$0.14	per Mcf	O & M (Shallow)	$0.19	/Mcf	Miscible Recovery	0%
Medium (1500 m)	$0.18	per Mcf	Medium	$0.25	/Mcf	Immiscible Recovery	0%
Deep	$0.23	per Mcf	Deep	$0.31	/Mcf	Primary + Secondary	75%
Offshore Factor	3.0	times	Offshore Factor	1.5	times	(of OGIP)	
CO_2 Pipeline Costs (Near)	$0.03	per Mcf	CO_2 Supply Costs (Natural)	$0.65	/Mcf	Net CO_2/EOR Ratic	0.0
Medium (<100 km)	$0.17	per Mcf	Gas Plant	$1.00	/Mcf	(Mcf/BO)	
Far (100-500 km)	$0.50	per Mcf	Power Plant[1]	$0.65	/Mcf		
Offshore Factor	2.0	times	Offshore Factor	1.0	times		

1. Reservoir Province			2. Reservoir Attributes[3]						3. Estimated CO_2 Injection Costs					4. Profits		5. CO_2 Volume[4]		6. Sequestration Potential			
Rank Sqstr (Gt)	Rank O&G (BOE)	Province Name	On/ Off Shore	Anthro. CO_2 Supply	Avg. Depth (m)	Oil Gravity (API)	Temp deg F	Gas Grav Unit	Field Cap ($/Mcf)	CO_2 Pipe ($/Mcf)	O&M Oper. ($/Mcf)	CO_2 Supply ($/Mcf)	Total Costs ($/Mcf)	Net Oil Price ($/Mcf)	Profit (Loss) ($/Mcf)	Reservoir Ratio-Vol CO_2/CH_4	CO_2 Equiv (Tcf)	CO_2 Sqstr Potential (75%) (Tcf)	(Gt)	Sqstr Costs ($/t)	Total Costs G $
4	2	Mesopotar	On	Med	2500	30	173	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.679	758.3	568.7	30.1	21.6	650
1	1	West Sibe	On	Far	2000	25	148	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.929	4188.4	3141.3	166.2	27.9	4628
5	4	Greater G	On	Med	2100	34	153	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.865	701.9	526.4	27.8	21.6	602
9	5	Rub Al Kh	On	Med	2500	35	173	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.679	463.5	347.6	18.4	21.6	397
14	8	North Sea	Off	Med	3500	40	222	0.6	0.54	0.34	0.38	0.65	1.91	0.00	-1.91	1.472	287.8	215.9	11.4	36.1	412
24	12	Villahermo	On/Off	Near	4300	40	262	0.6	0.51	0.05	0.35	0.65	1.56	0.00	-1.56	1.385	162.9	122.2	6.5	29.4	190
3	3	Zagros Fo	On	Med	3000	30	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	936.8	702.6	37.2	23.7	879
18	10	Volga-Ura	On	Near	2000	25	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	199.0	149.3	7.9	19.0	150
12	11	Niger Delt	On/Off	Near	3000	40	198	0.6	0.41	0.05	0.28	0.65	1.38	0.00	-1.38	1.549	377.8	283.4	15.0	26.2	392
37	18	Sirte Basi	On	Far	2500	40	173	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.679	90.2	67.6	3.6	27.9	100
30	13	Maracaibo	On/Off	Near	3000	25	198	0.6	0.41	0.05	0.28	0.65	1.38	0.00	-1.38	1.549	112.6	84.5	4.5	26.2	117
16	14	East Vene	On/Off	Near	3000	20	198	0.6	0.41	0.05	0.28	0.65	1.38	0.00	-1.38	1.549	256.7	192.5	10.2	26.2	266
8	9	Western G	On	Near	2200	35	158	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.826	463.9	347.9	18.4	19.0	349
21	15	Permian B	On	Near	2800	35	188	0.6	0.18	0.03	0.25	0.65	1.11	0.00	-1.11	1.604	174.9	131.1	6.9	21.0	146
32	21	S. Caspiar	Off	Med	3000	40	198	0.6	0.54	0.34	0.38	0.65	1.91	0.00	-1.91	1.549	102.2	76.7	4.1	36.1	146
54	27	West-Cen	Off	Far	3000	40	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	58.2	43.7	2.3	48.6	112
7	7	North Cas	On/Off	Near	3000	30	198	0.6	0.41	0.05	0.28	0.65	1.38	0.00	-1.38	1.549	475.4	356.5	18.9	26.2	493
68	28	Trias/Gha	On	Far	3000	48	198	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.549	42.4	31.8	1.7	29.9	50
71	23	Bohaiwan	On/Off	Near	2000	25	148	0.6	0.31	0.05	0.21	0.65	1.21	0.00	-1.21	1.929	39.9	29.9	1.6	22.9	36
13	17	Alberta Ba	On	Near	2000	36	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	373.6	280.2	14.8	19.0	281
70	37	San Joaqu	On	Near	1200	25	109	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.688	40.3	30.2	1.6	19.0	30
25	22	N. Alaska	On	Far	2000	25	148	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.929	160.1	120.1	6.4	27.9	177
11	19	Gulf Ceno	Off	Med	2300	40	163	0.6	0.41	0.34	0.28	0.65	1.68	0.00	-1.68	1.772	411.7	308.8	16.3	31.7	518
59	38	Tarim Bas	On	Far	3000	40	198	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.549	54.2	40.7	2.2	29.9	64
29	24	Timan-Pe	On	Far	2000	25	148	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.929	118.8	89.1	4.7	27.9	131
113	55	Jungger B	On	Far	3000	40	198	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.549	16.1	12.1	0.6	29.9	19
2	6	Qatar Arcl	On/Off	Near	2100	35	153	0.6	0.31	0.05	0.21	0.65	1.21	0.00	-1.21	1.865	1314.6	985.9	52.2	22.9	1195
84	49	Red Sea E	Off	Far	2300	38	163	0.6	0.41	1.00	0.28	0.65	2.34	0.00	-2.34	1.772	29.8	22.3	1.2	44.2	52
46	31	Middle Ca	On/Off	Med	2500	35	173	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	1.679	73.4	55.0	2.9	26.9	78
55	48	Bombay B	Off	Med	1800	38	139	0.6	0.41	0.34	0.28	0.65	1.68	0.00	-1.68	2.055	57.9	43.5	2.3	31.7	73
108	30	Widyan Ba	On	Med	3000	30	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	17.3	13.0	0.7	23.7	16
103	61	Carpathiar	On	Near	3500	42	222	0.6	0.18	0.03	0.25	0.65	1.11	0.00	-1.11	1.472	20.2	15.1	0.8	21.0	17
39	32	East Texa	On	Near	2300	35	163	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.772	87.8	65.8	3.5	19.0	66
118	63	Angara-Le	On	Med	2500	40	173	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.679	13.6	10.2	0.5	21.6	12
106	34	Songliao E	On	Near	2500	30	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	19.6	14.7	0.8	19.0	15
28	42	Malay Bas	Off	Far	1800	46	139	0.6	0.41	1.00	0.28	0.65	2.34	0.00	-2.34	2.055	119.8	89.8	4.8	44.2	210
123	39	Campos B	Off	Med	3900	29	242	0.6	0.68	0.34	0.47	0.65	2.14	0.00	-2.14	1.421	11.7	8.7	0.5	40.4	19
19	25	Grand Erg	On	Far	3000	45	198	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.549	192.9	144.6	7.7	29.9	229

34	35	Louisiana-	On	Near	2500	35	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	96.6	72.4	3.8	19.0	73
102	41	Central Su	On	Med	1200	30	109	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	2.688	21.2	15.9	0.8	21.6	18
45	50	Illizi Basin	On	Far	3000	45	198	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.549	76.2	57.2	3.0	29.9	90
110	52	Putamayo-	On	Far	2900	28	193	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.569	17.2	12.9	0.7	29.9	20
51	54	Vestford-H	Off	Far	3000	42	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	63.0	47.3	2.5	48.6	121
43	40	Baram De	On/Off	Far	2500	35	173	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	1.679	80.2	60.2	3.2	36.2	115
6	16	Amu-Dary	On	Far	2500	40	173	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.679	512.7	384.5	20.3	27.9	567
50	57	North Sak	On/Off	Far	2200	40	158	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	1.826	68.3	51.2	2.7	36.2	98
95	79	Gippsland	Off	Med	1500	40	124	0.6	0.41	0.34	0.28	0.65	1.68	0.00	-1.68	2.324	23.9	18.0	0.9	31.7	30
101	58	Llanos Ba	On	Med	3200	35	207	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.511	21.6	16.2	0.9	23.7	20
124	65	Tampico-N	On/Off	Med	3200	35	207	0.6	0.41	0.26	0.28	0.65	1.59	0.00	-1.59	1.511	11.6	8.7	0.5	30.1	14
121	92	Powder Ri	On	Near	1300	20	114	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.602	12.5	9.4	0.5	19.0	9
83	47	Reconcav	On/Off	Far	3900	29	242	0.6	0.51	0.75	0.35	0.65	2.26	0.00	-2.26	1.421	29.8	22.4	1.2	42.7	51
105	56	Los Angel	On	Near	1500	30	124	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.324	19.7	14.7	0.8	19.0	15
98	64	Bend Arch	On	Near	2500	35	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	22.7	17.0	0.9	19.0	17
93	62	Interior Ho	On	Med	2500	35	173	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.679	25.2	18.9	1.0	21.6	22
128	100	North Usty	On	Med	1000	20	99	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	3.111	10.6	7.9	0.4	21.6	9
35	45	Kutei Basi	On/Off	Far	2500	35	173	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	1.679	93.7	70.3	3.7	36.2	135
31	46	South Bar	Off	Far	3000	45	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	108.4	81.3	4.3	48.6	209
20	29	Anadarko	On	Near	2500	35	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	179.6	134.7	7.1	19.0	135
27	51	Northwest	Off	Far	1800	42	139	0.6	2.40	1.00	0.28	0.65	4.33	0.00	-4.33	2.055	128.8	96.6	5.1	81.9	418
144	116	Big Horn E	On	Med	3000	40	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	3.4	2.6	0.1	23.7	3
145	120	Faeroes-S	Off	Far	3000	40	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	3.1	2.3	0.1	48.6	6
109	75	Mekong/V	Off/On	Med	2500	34	173	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	1.679	17.3	13.0	0.7	26.9	18
97	83	Ventura Ba	On	Near	1600	25	129	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.213	23.0	17.3	0.9	19.0	17
77	97	South Sum	On	Near	1200	40	109	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.688	34.1	25.6	1.4	19.0	26
74	80	Sud	On	Far	1900	38	143	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	2.000	36.2	27.1	1.4	27.9	40
67	71	Fahud Sal	On	Far	800	32	89	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	2.949	44.5	33.4	1.8	27.9	49
111	95	Northwest	Off/On	Med	2000	37	148	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	1.929	16.6	12.4	0.7	26.9	18
151	103	Illinois Ba	On	Near	1500	25	124	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.324	1.6	1.2	0.1	19.0	1
149	130	South Om	On	Far	1200	40	109	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	2.688	2.2	1.6	0.1	27.9	2
81	96	Pannonian	On	Near	2000	40	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	30.5	22.9	1.2	19.0	23
33	53	Palo Duro	On	Near	1800	35	139	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.055	99.4	74.6	3.9	19.0	75
131	99	Fergana E	On	Far	2000	35	148	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.929	8.7	6.5	0.3	27.9	10
154	127	East Flank	On	Far	1200	38	109	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	2.688	0.5	0.4	0.0	27.9	1
73	87	Nepa-Botu	On	Far	2500	40	173	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.679	36.9	27.7	1.5	27.9	41
91	111	Southern A	On/Off	Med	1200	40	109	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	2.688	25.4	19.1	1.0	26.9	27
48	66	Williston E	On	Near	1400	35	119	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.453	69.2	51.9	2.7	19.0	52
137	105	Southern C	On	Med	2500	35	173	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.679	6.2	4.6	0.2	21.6	5
146	129	Saline-Co	On/Off	Med	4000	38	247	0.6	0.51	0.26	0.35	0.65	1.77	0.00	-1.77	1.407	3.1	2.3	0.1	33.4	4
76	91	Penyu/We	Off	Far	3000	40	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	34.4	25.8	1.4	48.6	66
104	107	Michigan	On	Near	2000	38	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	20.1	15.0	0.8	19.0	15
85	104	Bonaparte	Off	Far	2000	45	148	0.6	0.41	1.00	0.28	0.65	2.34	0.00	-2.34	1.929	29.5	22.1	1.2	44.2	52
64	89	Ma 'Rib-A	On	Far	2000	45	148	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.929	48.4	36.3	1.9	27.9	53
139	117	Williston B	On	Near	2000	35	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	5.8	4.3	0.2	19.0	4
115	86	San Jorge	On/Off	Far	2500	30	173	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	1.679	14.9	11.2	0.6	36.2	21
15	33	Greater Sa	On/Off	Far	1300	39	114	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	2.602	279.2	209.4	11.1	36.2	401
138	121	Talara Ba	On/Off	Med	1700	35	134	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	2.116	6.1	4.6	0.2	26.9	7
72	68	Neuquen I	On	Med	3000	32	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	39.0	29.3	1.5	23.7	37
148	143	Anah Grab	On	Med	1500	15	124	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	2.324	2.8	2.1	0.1	21.6	2
52	77	Magallene	On/Off	Far	1900	40	143	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	2.000	62.8	47.1	2.5	36.2	90
36	60	Labrador-N	Off	Far	2100	40	153	0.6	0.41	1.00	0.28	0.65	2.34	0.00	-2.34	1.865	90.6	68.0	3.6	44.2	159
60	73	North Sum	On	Med	3000	55	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	52.0	39.0	2.1	23.7	49
58	72	Po/Adriatic	On/Off	Near	3000	20	198	0.6	0.41	0.05	0.28	0.65	1.38	0.00	-1.38	1.549	54.4	40.8	2.2	26.2	56

65	74	Pelagian E	Off	Far	2500	35	173	0.6	0.41	1.00	0.28	0.65	2.34	0.00	-2.34	1.679	48.2	36.1	1.9	44.2	85
112	93	Middle Ma	On	Med	2200	30	158	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.826	16.2	12.2	0.6	21.6	14
26	43	Dnieper-D	On	Near	2500	35	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	132.8	99.6	5.3	19.0	100
99	109	Wyoming	On	Med	3000	40	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	22.5	16.9	0.9	23.7	21
66	82	SW Wyom	On	Near	3000	40	198	0.6	0.18	0.03	0.25	0.65	1.11	0.00	-1.11	1.549	46.9	35.2	1.9	21.0	39
38	88	Ordos Bas	On	Med	1000	15	99	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	3.111	89.0	66.7	3.5	21.6	76
57	84	Thai Basin	Off	Med	2000	50	148	0.6	0.41	0.34	0.28	0.65	1.68	0.00	-1.68	1.929	55.7	41.8	2.2	31.7	70
126	106	Assam	On	Far	3500	33	222	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.472	11.0	8.3	0.4	29.9	13
155	153	Murzak	On	Far	2500	40	173	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.679	0.0	0.0	0.0	27.9	0
150	119	Cambridge	On	Near	2000	30	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	1.8	1.3	0.1	19.0	1
141	136	Santa Mar	On	Near	1500	23	124	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.324	4.9	3.7	0.2	19.0	4
53	69	Sichuan B	On	Near	3500	40	222	0.6	0.18	0.03	0.25	0.65	1.11	0.00	-1.11	1.472	60.0	45.0	2.4	21.0	50
140	114	Nemaha U	On	Near	2500	30	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	5.4	4.1	0.2	19.0	4
152	144	Khleisha U	On	Far	2000	20	148	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.929	1.5	1.2	0.1	27.9	2
41	78	Bintuni/Su	Off	Far	1100	35	104	0.6	0.41	1.00	0.28	0.65	2.34	0.00	-2.34	2.881	85.9	64.4	3.4	44.2	151
134	128	Palawan S	Off	Far	3800	35	237	0.6	0.68	1.00	0.47	0.65	2.80	0.00	-2.80	1.426	8.0	6.0	0.3	52.9	17
63	94	Irrawaddy	On/Off	Far	1500	36	124	0.6	0.31	0.75	0.21	0.65	1.92	0.00	-1.92	2.324	49.5	37.1	2.0	36.2	71
42	76	Ghaba Sa	On	Far	1100	34	104	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	2.881	83.0	62.2	3.3	27.9	92
147	131	Cherokee	On	Near	2200	32	158	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.826	2.9	2.1	0.1	19.0	2
17	26	NW Germ	On/Off	Near	2500	30	173	0.6	0.31	0.05	0.21	0.65	1.21	0.00	-1.21	1.679	237.9	178.4	9.4	22.9	216
82	102	Santa Cru	On	Far	3800	50	237	0.6	0.23	0.50	0.31	0.65	1.69	0.00	-1.69	1.426	30.2	22.7	1.2	31.9	38
142	145	Euphrates	On	Near	1500	36	124	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.324	4.2	3.1	0.2	19.0	3
129	133	Denver Ba	On	Near	1800	35	139	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.055	10.3	7.7	0.4	19.0	8
136	147	Wind Rive	On	Med	3000	40	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	6.7	5.0	0.3	23.7	6
116	124	Uinta-Pice	On	Med	1600	30	129	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.213	14.8	11.1	0.6	19.0	11
79	110	Yenisey-K	On	Far	2500	40	173	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.679	32.2	24.2	1.3	27.9	36
94	115	Madre dos	On	Far	2500	35	173	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.679	24.5	18.4	1.0	27.9	27
44	67	San Juan	On	Near	2000	30	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	77.1	57.9	3.1	19.0	58
87	108	Arkoma Ba	On	Med	2500	35	173	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.679	29.2	21.9	1.2	21.6	25
135	146	Bohemia	On	Near	1500	35	124	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.324	7.7	5.8	0.3	19.0	6
80	112	North Egy	On/Off	Med	2000	35	148	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	1.929	32.2	24.2	1.3	26.9	34
78	113	Azov-Kuba	On	Far	2300	40	163	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	1.772	33.0	24.7	1.3	27.9	36
153	150	Cuyo Basi	On	Med	2000	32	148	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.929	0.6	0.4	0.0	21.6	1
56	81	New Guine	On	Far	3000	44	198	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.549	55.8	41.8	2.2	29.9	66
61	98	Browse Ba	Off	Far	2000	45	148	0.6	0.41	1.00	4.05	0.65	6.11	0.00	-6.11	1.929	50.1	37.6	2.0	115.5	230
107	140	Eromanga	On	Far	1600	43	129	0.6	0.14	0.50	0.19	0.65	1.47	0.00	-1.47	2.213	18.8	14.1	0.7	27.9	21
10	20	Mediterran	Off	Far	3000	40	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	428.3	321.2	17.0	48.6	825
125	141	Taranaki B	Off	Med	3500	50	222	0.6	0.54	0.34	0.38	0.65	1.91	0.00	-1.91	1.472	11.5	8.6	0.5	36.1	16
143	151	Sedgwick	On	Near	2200	32	158	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.826	4.0	3.0	0.2	19.0	3
89	123	Ganges-B	On/Off	Med	2000	35	148	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	1.929	27.6	20.7	1.1	26.9	29
127	138	Abu Ghara	On	Med	3000	33	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	10.7	8.0	0.4	23.7	10
69	101	North Car	On	Near	2000	30	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	41.1	30.8	1.6	19.0	31
96	125	Rocky Mo	On	Near	2500	35	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	23.2	17.4	0.9	19.0	17
23	44	Anglo-Dut	Off/On	Near	2000	28	148	0.6	0.31	0.05	0.21	0.65	1.21	0.00	-1.21	1.929	169.1	126.8	6.7	22.9	154
119	142	Hammerfe	Off	Far	3000	42	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	13.0	9.8	0.5	48.6	25
120	139	Afghan-Ta	On	Far	3500	36	222	0.6	0.18	0.50	0.25	0.65	1.58	0.00	-1.58	1.472	12.5	9.4	0.5	29.9	15
49	70	Indus	Off	Med	3000	35	198	0.6	0.54	0.34	0.38	0.65	1.91	0.00	-1.91	1.549	69.1	51.8	2.7	36.1	99
114	137	Irish Sea	Off	Near	3000	40	198	0.6	0.54	0.34	0.38	0.65	1.91	0.00	-1.91	1.549	15.6	11.7	0.6	36.1	22
133	154	Macuspan	On/Off	Med	4300	40	262	0.6	0.51	0.26	0.35	0.65	1.77	0.00	-1.77	1.385	8.2	6.1	0.3	33.4	11
122	148	Alps	On	Near	2000	35	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	12.0	9.0	0.5	19.0	9
130	149	Saigon	Off	Far	3000	35	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	9.3	7.0	0.4	48.6	18
90	135	East Java	On/Off	Med	1200	30	109	0.6	0.31	0.26	0.21	0.65	1.42	0.00	-1.42	2.688	25.8	19.4	1.0	26.9	28
92	126	Sulaiman-	On	Med	2800	40	188	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.604	25.3	19.0	1.0	23.7	24
100	134	Sacramen	On	Near	2200	40	158	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.826	22.0	16.5	0.9	19.0	17

132	155	E. Cordille	On	Near	2500	28	173	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.679	8.4	6.3	0.3	19.0	6
40	59	Burgos/Sa	On/Off	Med	3000	30	198	0.6	0.41	0.26	0.28	0.65	1.59	0.00	-1.59	1.549	86.9	65.2	3.4	30.1	104
75	118	German-P	On	Near	2000	35	148	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	1.929	36.1	27.0	1.4	19.0	27
22	36	Lena-Vilyu	On	Med	3000	35	198	0.6	0.18	0.17	0.25	0.65	1.25	0.00	-1.25	1.549	171.0	128.3	6.8	23.7	160
62	90	Tobago T	Off	Med	3100	35	203	0.6	0.54	0.34	0.38	0.65	1.91	0.00	-1.91	1.530	49.9	37.4	2.0	36.1	71
86	132	Pyrenean	On	Near	1500	35	124	0.6	0.14	0.03	0.19	0.65	1.00	0.00	-1.00	2.324	29.3	22.0	1.2	19.0	22
88	122	Yingehai	Off	Far	3000	40	198	0.6	0.54	1.00	0.38	0.65	2.57	0.00	-2.57	1.549	28.5	21.4	1.1	48.6	55
47	85	Transylvar	On	Med	2000	35	148	0.6	0.14	0.17	0.19	0.65	1.14	0.00	-1.14	1.929	69.6	52.2	2.8	21.6	60
117	152	Ludlov Sa	Off	Med	2400	40	168	0.6	0.41	0.34	0.28	0.65	1.68	0.00	-1.68	1.740	14.1	10.6	0.6	31.7	18
		TOTAL 155 Basins															18664	13998	740	27.6	20451
		TOTAL WORLD															20101	15076	797	27.6	22025
																		545.5	190.0		