Oil Sands Research and Development

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This report builds on the work of others, who, over the years, have contributed to making the case for increased collaborative oil sands R&D. Organizations such as AOSTRA, CONRAD, AERI, ARC, CANMET, NCUT, PTAC and many industry leaders need to be recognized.
ABBREVIATIONS

AACI  AERI-ARC Core Industry program
ACR  Alberta Chamber of Resources
ADOE  Alberta Department of Energy
AERI  Alberta Energy Research Institute
AOSTRA  Alberta Oil Sands Technology and Research Authority
ARC  Alberta Research Council
ATP  Alberta Taciuk Processor
Bcf  Billion cubic feet
Bpd  Barrels per day
ASRIP  Alberta Science and Research Investment Program
BERD  Business Expenditures on Research and Development
CANMET  Canada Centre for Mineral and Energy Technology
CERI  Canadian Energy Research Institute
CETC  CANMET Energy Technology Centre
CFI  Canada Foundation for Innovation
COURSE  Core University Research in Sustainable Energy
CRC  Canada Research Chairs
CSS  Cyclic Steam Stimulation
ERCB  Energy Resources Conservation Board
EUB  Energy and Utilities Board
IETP  Innovative Energy Technology Program
IRAP  Industrial Research Assistance Program
NCUT  National Centre for Upgrading Technology
NRC  National Research Council
NRCan  Natural Resources Canada
NSERC  National Science and Engineering Research Council
OSTR  Oil Sands Technology Roadmap
PTAC  Petroleum Technology Alliance of Canada
PTRC  Petroleum Technology Research Centre
RFP  Request for Proposal
SAGD  Steam Assisted Gravity Drainage
SAP  Steam Assisted Process
SCO  Synthetic Crude Oil
SRC  Saskatchewan Research Council
SR&ED  Scientific Research and Experimental Development
THAI  Toe to Heel Air Injection
TPC  Technology Partnerships Canada
VAPEX  Vapour Recovery Extraction
URSI  University Research and Strategic Investments
UTF  Underground Test Facility
EXECUTIVE SUMMARY

Alberta oil sands are the world’s largest reserves of bitumen. The initial volume in place is 1.7 trillion barrels of bitumen, and, based on current technology, remaining established reserves are 174 billion barrels. The oil sands are, undoubtedly, a very significant resource by Alberta standards. They dwarf conventional oil and natural gas combined. Alberta oil sands are also very significant by world standards. Canada and Alberta now rank second in the world for oil reserves behind Saudi Arabia. The Alberta oil sands are indeed a world-class asset.

However, Alberta's oil sands resource is not a uniform resource. There are significant differences between regions and between geological zones. In fact, the quality of bitumen deposits spans a range from highly attractive reservoirs to deposits that have been nearly forgotten. Rich and thick oil sands are highly attractive and are the foundation for the current build up of oil sands projects in Athabasca. Recovery factors for high-quality reservoirs can reach as high as 90% for surface mining and 60% for SAGD. By contrast, some very large bitumen deposits have recovery factors of zero.

For the purpose of this study, the deposits that are exploitable using existing commercial technologies were classified under one of three categories:

- Economically recoverable by Steam-Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS) or equivalent thermal technology;
- Economically recoverable by surface mining; and,
- Capable of cold primary production.

The total of all deposits recoverable with existing commercial technologies represent 43% of Alberta’s oil sand resource. The balance, or 57%, is currently deemed not recoverable by any existing commercial technology and has an assigned recovery factor of zero. These deposits were classified into one of the following categories:

- Bitumen in carbonate formations;
- Deposits too thin for commercial thermal processes;
- Deposits with insufficient cap rock, shale or clay barrier;
- Deposits too deep for surface mining but too shallow for SAGD; and,
- Deposits in communication with low pressure or depleted gas caps.

By far, the two largest categories of deposits with no recovery factor are bitumen in carbonate formations and thin oil sands. Together, they represent 50% of the total Alberta oil sands resource.

<table>
<thead>
<tr>
<th>Bitumen Deposits with No Recovery Factor</th>
</tr>
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<tbody>
<tr>
<td>Carbonates</td>
</tr>
<tr>
<td>Insufficient cap rock</td>
</tr>
<tr>
<td>Intermediate depth</td>
</tr>
<tr>
<td>Low pressure gas cap</td>
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</tbody>
</table>

Bitumen in Carbonate Formations

Over one quarter of Alberta's bitumen resources are not contained in sand formations but in carbonate formations. Bitumen is present in a dual porosity system. Bitumen is held in the carbonate matrix. However, bitumen also occurs in natural fractures called “vugs” with diameters of up to 10 cm and larger. An important challenge is that these formations are highly variable over short distances because of the complexity of the natural fracture system.

The most significant carbonate deposit is the Grosmont platform in Athabasca. The Grosmont platform is 500 km in length and 150 km in width and buried at depths ranging from 250 m to 420 m. Its total thickness is approximately 170 to 180 meters. Pay thickness varies considerably from 25 m to over 80 m. Bitumen saturation is high. Bitumen accumulation is highest on the eastern margin. However, bitumen is heavier than Athabasca oil sands, with API gravity of 5° to 9°.

The Grosmont was the object of three recovery pilots in the 1980s. Results were described as spectacular but erratic and the production pilots were abandoned. The Grosmont formation is difficult to develop because it exhibit close to complete saturation of high viscosity bitumen. Natural fractures add considerable difficulties for drilling, completions and steam containment. There is presently no commercial method to recover bitumen from Alberta carbonate formations and the recovery factor for this deposit is zero.
Thin Oil Sands

Thin oil sand deposits are found everywhere as they surround the central thick channel oil sands. Thin oil sands are a considerable resource. For the purpose of this study, deposits thinner than 10 m were considered not recoverable with current commercial technologies and were assigned a recovery factor of zero. Using this cutoff, thin oil sands account for one quarter of the total Alberta bitumen resource. Over 90% of thin oil sands are located in the Athabasca region. If a larger thickness had been chosen as the cutoff (for example 25 m as for current commercial SAGD projects), then the volume of thin oil sands identified would have been significantly larger.

Thin bitumen deposits are less attractive for SAGD operators because they present reduced economics and increased environmental footprints. The key factors are as follows:

- Thinner deposits contain less oil over the producing horizontal well.
- In SAGD, a gravity drive must be maintained. This dictates the maximum width of the steam chamber as a multiple of its maximum height. Thinner deposits result in a narrower steam chamber and therefore reduced well spacings. This increases capital costs and the environmental footprint on the surface.
- Thinner deposits will lose more heat to the over and under burden.

There are few, if any, known R&D programs and industry developments aimed at developing thin oil sands.

Oil Sands Research and Development

Research and development were clearly instrumental in making oil sands the significant economic reality it is today. R&D and technology development must again be called into service to meet current challenges and opportunities.

New technologies will be required to improve production of bitumen and heavy oil, whether it is to increase the extent of recovery, to increase the rate of recovery, to lower costs, to address issues related to natural gas, water and diluent or to minimize environmental footprint such as tailings ponds and surface disturbance. The future of oil production in Alberta lies with improved methods for bitumen recovery. This can be accomplished by incremental improvements to existing methods, or, by developing new and novel ones. Oil sands research and development is an important vehicle for the emergence of the innovative technologies that will be necessary to economically recover the full extent of Alberta’s vast bitumen resource while protecting the environment.

The first step is to take stock of current oil sands R&D activities, both publicly and privately funded.
Publicly Funded R&D

Total funding from governments for bitumen and heavy oil R&D was approximately $117 million in the five years from fiscal 1998-99 to fiscal 2002-03. The funding organizations that provided most funds were by a wide margin Natural Resources Canada (NRCan) ($46.7 million) and the Alberta Energy Research Institute (AERI) ($30.6 million). NRCan funding was almost exclusively directed to the operations of the laboratories and pilot plants located in Devon, Alberta. AERI, by contrast funded a broad mix of targeted projects from fundamental research to commercialization, performed by several facilities and organizations.

Public funds provided for oil sands research were utilized by research organizations to conduct projects. The largest recipient ($38.9 million) was the National Center for Upgrading Technology (NCUT) in Devon, Alberta which is a federal-provincial partnership and received funds from NRCan, AERI, ARC, as well as other government sources. The second largest recipient was the associated federal CANMET facility in Devon ($18.7 million). This facility is funded by NRCan and industry. It conducts research into advanced separation technologies related to petroleum. The University of Alberta, the Alberta Research Council and the University of Calgary each received approximately $12 million over five years for bitumen and heavy oil research.

The largest amount of government funding was directed at applied research and reflects the substantial amount of work conducted by NCUT and ARC. The next largest category was fundamental research which is conducted mostly by universities. Demonstration trials attracted a relatively small level of public funding.

Projects concerned with the recovery bitumen and heavy oil attracted the most funding. Upgrading commanded the second most important level of funding. This is due in a large part to the research conducted at NCUT. The lowest level of funding was directed at research conducted into environmental issues. The aggregate amount of funds spent on environmental research was slightly more than 10% of the total amount spent on oil sands research.

Approximately 43% of oil sands volume in place is suitable for current commercial technologies such as surface mining, SAGD and CSS. The other types of buried deposits
can not be economically developed unless new technologies are made available. Most of the public research appears to have been directed at improving the efficiency of existing or near commercial technologies designed for deposits that are presently the object of active development. A much lower level of funding was targeted at untapped deposits. Very little work appears to have been directed at thin deposits. No projects could be identified that targeted bitumen in carbonate formations.

The current level of public funding averaged $23 million per year in the last few years. By contrast, the Alberta Oil Sands Technology and Research Authority (AOSTRA), which was established in 1974 by the Alberta government for oil sands R&D, spent on average $57 million per year (2004 dollars) for a 20 year period from the mid-1970s to the mid-1990s. This amount is more than double the funds currently contributed by the provincial and federal governments combined for oil sands R&D.

**Privately Funded R&D**

Canadian business R&D expenditures for oil and gas extraction, which includes oil sands recovery, dipped between 1998 and 1999, in all probability because of low oil prices. However R&D expenditures have now recovered, likely in response to increases in oil prices. Oil and gas R&D in Canada now stands at double the rate of 1994-99.
The same growth pattern noted for oil and gas is repeated for oil sands: a significant growth in privately funded oil sands R&D occurred between 1999 and 2004. On average, corporate oil sands R&D expenditures during 2000-2004 were $146 million per year and reached a high of approximately $185 million in 2004.

It is also notable that only a few companies are responsible for most of the research and development. The top 8 companies account for 80% to 90% of all oil sands R&D in each of the years surveyed.

It would be reasonable to anticipate that the pattern of steadily increasing amounts of funds dedicated to oil sands R&D will continue in the coming years. Oil prices are expected to remain at high levels. Another element of evidence is the uptake by industry of Alberta Energy's Innovative Energy Technology Program (IETP) introduced last year to support demonstration pilots for new technologies in Alberta. For 2005 and future years, the amounts already announced under IETP for oil sands pilots alone are:
- $39.7 million from Alberta Energy;
- $92.6 million from industry;
- For a total of $132.3 million of new oil sands demonstration pilots.

Full uptake of the program would lead to over $600 million of new demonstration pilots in Alberta in years to come.

As noted earlier, in the last few years, the average amount of public funds dedicated to oil sands R&D was on average $23 million per year. Therefore, the $146 million per year spent on average by industry represent a ratio of if 6.3 to 1 industry to government funding. It appears that industry is carrying most of the burden for oil sands R&D.

Privately funded R&D was mostly directed at demonstration and applied research. Fundamental R&D accounted for only an estimated 7% of privately funded research. Industry is driven by business and operational goals and therefore allocates most of its R&D dollars to applied research which is aimed at resolving known technical challenges, and to demonstration pilots which are aimed at proving technologies that have been developed at the bench scale.

The majority of the investment in privately funded R&D was dedicated to the improved recovery of bitumen. Operators of oil sands mines conduct R&D for improving the process, particularly for reducing the energy intensity of the water extraction process. SAGD and CSS operators seek to improved overall recovery and extend the applicability
of these processes. The level of environmental research is similar to the public sector and falls between 10% and 20%. Water and soil are the most frequently mentioned topics for environmental research.

The vast majority of the work was for deposits that are recoverable by in situ thermal technologies such as SAGD and CSS. SAGD demonstration pilots appear to command the lion's share of budgets. Over the last few years several demonstration pilots are aimed at improving SAGD operations have been constructed and operated. These efforts have sought to develop technologies such as:

- The adaptation of SAGD to specific reservoir conditions;
- Developing an understanding of operational parameters such as steam chamber growth, the impact of shale or clay layers, adjustments for water zones; steam to oil ratio, etc;
- Low-pressure SAGD for shallow oil sands;
- Artificial lift technologies for low-pressure SAGD;
- The addition of solvents and diluent to the steam in SAGD operations in order to enhance performance and reduce energy intensity;

Shallow deposits were the type of inaccessible deposits that was being targeted, mainly with low pressure SAGD. No R&D was identified that was directed at bitumen in carbonate formation or at deposits with insufficient cap rock, shale or clay barrier. Only a small amount could be deemed applicable to thin oil sands.
Key Messages
The key points that we made by this report can be summarized as follows:

- The oil sands are a large resource by Alberta standards. The conventional oil and natural gas sector has served Alberta well. Alberta’s bitumen resource is larger than conventional oil and natural gas combined. Alberta’s energy future is with the oil sands.

- Alberta oil sands are also a large resource by world standards. Because of the oil sands, Alberta is ranked second in the world for the size of oil reserves, behind the reserves of conventional oil of Saudi Arabia. The Alberta oil sands are a world class resource.

- Alberta oil sands will last a very long time. Even after production rates are increased three to five times current rates, Alberta’s established reserves of bitumen will still last for a century.

- There are no commercial recovery technologies that are applicable for more than half of Alberta's bitumen resources. The current build-up of oil sands developments is based on less than half the resource.

- Bitumen deposits for which there are no commercial technologies and therefore a recovery factor of zero are:
  - Bitumen in carbonate formations;
  - Deposits too thin for commercial thermal processes;
  - Deposits with insufficient cap rock, shale or clay barriers;
  - Deposits too deep for surface mining but too shallow for SAGD; and,
  - Deposits in communication with low pressure gas cap

- Bitumen deposits for which there is no recovery factor offer a significant opportunity that requires the development of new technologies by investment in R&D.

- Current commercial technologies recover only a fraction of the bitumen volume in place. A second, related, significant opportunity is the development of improved technologies to increase recovery factors, particularly for deposits exploited with cold primary production.

- Current commercial technologies are faced with significant technical challenges for which technology improvements are required:
  - High usage of natural gas;
  - High usage of water;
  - High requirements for diluent; and,
  - Environmental impact, such as tailings ponds and emissions of greenhouse gas.

- The current level of public funding for oil sands R&D is relatively small as compared to:
The levels spent by governments in the 1980s through AOSTRA; Current support for oil sands R&D by the provincial and federal governments combined is approximately $23 million per year and is less than half the amount spent by the Alberta government on AOSTRA from the mid-1970s to the mid-1990s.

The level spent currently by industry; Industry spent an average of $146 million per year on oil sands R&D between 2000 and 2004, or 6.3 times the level spent by the provincial and federal governments combined.

- Privately funded R&D was curtailed during the last decade because of low oil prices. However in the last few years funding levels have come back and stood at a high of approximately $185 million in 2004. Most of industry's R&D budgets are earmarked for demonstration pilots, and for applied research.

- A considerable amount of technical information resides in old AOSTRA files. This is a depreciating asset that should be made to contribute before it is too late.

**Recommendations**

The following recommendations are made for further consideration:

1. The level of R&D funding by governments and industry should be increased to become commensurate with the wealth generated by the resource. The recent IETP program is acknowledged as an important milestone. The future prosperity that optimal development of the resource would return to Alberta in terms of increased economic activity and government revenue is huge.

2. A joint government and industry consultation should be undertaken to outline a clear technology vision and strategy for the whole resource. While individual companies may have a long term R&D strategy for their areas of operations, leadership from the government of Alberta, as the resource owner, is required for deposit wide technology challenges, including bitumen deposits for which there is no recovery factor, increases in deposit wide recovery factors, and regional environmental issues.

3. The vehicle for technology vision and strategy development should be found within existing government and industry technology organizations and agencies. Policy should avoid creating a new agency.

4. A joint government-industry funding vehicle should be considered to support deposit wide technology programs. Funding should be long term and substantial.

5. Funding for deposit wide oil sands R&D should be provided, in part, by oil royalties as a sustaining reinvestment to maintain and improve the quality of the oil sands resource.

6. The existing capacity for R&D in industry, universities and government laboratories should be utilized. Recognition should also be given to the fact
that a significant amount of R&D capacity resides in industry and that industry continues to be the primary vehicle for demonstrating and commercializing oil sands R&D. Existing R&D organizations need to remain relevant, creative and coordinated in order to warrant funding.

7. A program should be initiated to place old AOSTRA files in the public domain for use by existing researchers before obsolescence and to avoid spending public or private funds on repeating work that was done 20 years ago.
# TABLE OF CONTENTS

ACKNOWLEDGEMENTS .......................................................................................................................... 3
ABBREVIATIONS ...................................................................................................................................... 4
EXECUTIVE SUMMARY .......................................................................................................................... 6
TABLE OF CONTENTS .............................................................................................................................. 16
TABLES AND FIGURES ............................................................................................................................. 18
INTRODUCTION ........................................................................................................................................ 20
PURPOSE .................................................................................................................................................. 21
SCOPE ....................................................................................................................................................... 23
STRATEGIC IMPORTANCE ......................................................................................................................... 24
  A World Class Resource ......................................................................................................................... 24
  Global and United States Petroleum Demand ...................................................................................... 25
  Alberta Oil Sands Supply ....................................................................................................................... 26
RESOURCE DESCRIPTION ......................................................................................................................... 33
  Introduction ............................................................................................................................................ 33
  Terminology ............................................................................................................................................ 33
  The Recovery Factor ............................................................................................................................... 34
  Ultimate Potential ................................................................................................................................ 34
  Volume In Place and Established Reserves of Oil & Gas Resources .................................................... 36
  Volume In Place and Established Reserves of Oil Resources ................................................................ 46
    Conventional Oil ................................................................................................................................. 46
    Bitumen ............................................................................................................................................... 47
  The Future Is Oil Sands ............................................................................................................................ 47
Overview of Bitumen Deposits .................................................................................................................. 58
Bitumen Deposits Accessible with Commercial Recovery Technologies ............................................ 62
  Deposits Recoverable by SAGD, CSS or Equivalent Thermal Technology ........................................... 62
  Surface Mineable Oil Sands .................................................................................................................... 62
  Deposits Capable of Cold Primary Production ...................................................................................... 64
Bitumen Deposits with No Recovery Factor .............................................................................................. 65
  Bitumen in Carbonate Formations ........................................................................................................... 65
  Thin Oil Sands ....................................................................................................................................... 72
  Deposits Too Deep for Surface Mining but Too Shallow for SAGD ....................................................... 73
  Deposits with Insufficient Cap Rock, Shale or Clay Barrier ................................................................. 74
  Deposits in Communication with Low Pressure Gas Caps ................................................................... 75
TECHNICAL CHALLENGES ....................................................................................................................... 77
  Natural Gas Consumption .................................................................................................................... 77
  Fresh Water Consumption .................................................................................................................... 77
  Diluent Usage ....................................................................................................................................... 78
PUBLICLY FUNDED OIL SANDS RESEARCH AND DEVELOPMENT ........................................................... 79
Methodology .............................................................................................................................................. 79
  Stage of R&D ....................................................................................................................................... 80
  Stage of Resource Development ......................................................................................................... 80
  Improvement Opportunity ...................................................................................................................... 81
TABLES AND FIGURES

Figure 1 - North American Petroleum Demand (Thousand barrel per day) ........................................... 25
Table 1 - Oil Sands Production (barrels per day) .................................................................................... 27
Table 2 - Ultimate Potential of Oil & Gas Resources (Metric Units) ...................................................... 34
Table 3 - Ultimate Potential of Oil & Gas Resources (Imperial Units) .................................................... 35
Table 4 - Ultimate Potential of Oil & Gas Resources (Equivalent Metric Units) ................................... 36
Table 5 - Ultimate Potential of Oil & Gas Resources (Equivalent Imperial Units) ............................... 36
Figure 2 – Oil & Gas Resources Percent of Ultimate Volume In Place .................................................. 37
Figure 3 – Oil & Gas Resources Percent of Ultimate Recoverable Potential ....................................... 38
Table 6 – Oil & Gas Resources Volume In Place and Reserves (Metric Units) ....................................... 39
Table 7 – Oil & Gas Resources Volume In Place and Reserves (Imperial Units) ..................................... 40
Table 8 – Oil & Gas Resources Volume In Place and Reserves (Equivalent Metric Units) ................... 41
Table 9 – Oil & Gas Resources Volume In Place and Reserves (Equivalent Imperial Units) .................. 42
Figure 4 – Oil & Gas Resources Percent of 2004 Annual Production ..................................................... 43
Figure 5 – Oil & Gas Resources Percent of Remaining Established Reserves ..................................... 44
Figure 6 – Oil & Gas Resources Percent of Currently Unrecoverable Volume In Place ....................... 45
Table 10 - Oil Resources Volume In Place and Reserves (Metric Units) .............................................. 48
Table 11 - Oil Resources Volume In Place and Reserves (Imperial Units) ............................................ 49
Figure 7 - Conventional Oil Resources (Metric Units) ....................................................................... 50
Figure 8 - Conventional Oil Resources (Imperial Units) ..................................................................... 51
Figure 9 - Conventional Oil Resources Unrecoverable Volume In Place (Metric Units) .................... 52
Figure 10 - Conventional Oil Resources Unrecoverable Volume In Place (Imperial Units) ................ 53
Figure 11 - Bitumen Resources (Metric Units) .................................................................................... 54
Figure 12 - Bitumen Resources (Imperial Units) ................................................................................ 55
Figure 13 - Bitumen Resources Unrecoverable Volume In Place (Metric Units) ................................. 56
Figure 14 - Bitumen Resources Unrecoverable Volume In Place (Imperial Units) .............................. 57
Table 12 - Bitumen Deposits (Metric Units) ....................................................................................... 59
Table 13 - Bitumen Deposits (Imperial Units) ..................................................................................... 60
Figure 15 - Bitumen Deposits with No Recovery Factor ...................................................................... 61
Table 14 – Bitumen in Carbonate Formations ..................................................................................... 66
Figure 16 – Location of the Grosmont Carbonate Platform ................................................................. 67
Table 15 – Reservoir Parameters for Carbonate Production Pilots ...................................................... 69
Table 16 - AOSTRA Yearly Expenditures ............................................................................................ 84
Figure 17 - AOSTRA Yearly Expenditures ......................................................................................... 85
Table 17 - Business Enterprise R&D for Canadian Oil and Gas Extraction ($ million) .................... 89
Figure 18 - Business Enterprise R&D for Canadian Oil and Gas Extraction ..................................... 89
Table 18 –Oil and Gas R&D Expenditures by Companies in Top 100 R&D Spenders ....................... 90
Table 19 - Oil Sands Privately Funded R&D Expenditures ($ million) .............................................. 93
Figure 19 - Oil Sands Privately Funded R&D Expenditures ............................................................... 94
Figure 20 – Research Stage for Publicly Funded R&D ..................................................................... 95
Figure 21 – Research Stage for Privately Funded R&D ................................................................... 96
Figure 22 – Stage of Resource Development for Publicly Funded R&D .......................................... 97
Figure 23 – Stage of Resource Development for Privately Funded R&D ....................................... 98
Figure 24 – Publicly and Privately Funded R&D by Deposit Type ................................................................. 99
Alberta oil sands contain the world’s largest reserves of bitumen. On the basis of current technologies and economic conditions, Alberta’s remaining established reserves of bitumen have been estimated at 174 billion barrels. Alberta’s oil reserves are now ranked second in the world, behind the reserves of conventional crude oil of Saudi Arabia. Recovery and upgrading of this vast resource are increasingly important areas of economic activity in the province. Existing mining operations are being expanded. New mining and in-situ recovery projects are being developed. Investments in the oil sands industry are expected to exceed $100 billion between 1996 and 2015.

It has not always been this way. Thirty years ago, oil sands were a fledging industry and Alberta reserves of bitumen were not recognized by many international organizations. While several elements contributed to this impressive turnaround, the development and commercialization of new technologies were undoubtedly major contributors. Significant technological changes in surface mining, along with the introduction of major in situ technologies such as Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD) placed the oil sands on a solid economic foundation and caused the world to recognize the magnitude of Alberta’s bitumen resources. Today, the outcome is that the pace and scale of oil sands developments are at a level that could only be dreamed of thirty years ago.

While it would be easy to be complacent about past successes, Alberta Energy has chosen a different path and is proposing an ambitious vision for capturing a maximum of value and benefits for Alberta residents. Alberta Energy’s vision calls for more than tripling oil sands production by 2020, and for substantially increasing upgrading and value added processing in the province.

However, significant technical challenges must be overcome for this vision to be realized. Thirty years ago investments in research and development were marshalled in order to make oil sands a significant economic reality. Today, R&D and technology development must again be called into service to grow the oil sands industry to the scale and value justified by the magnitude of the resource.

The first step is to take stock of current oil sands R&D activities. Two years ago, Alberta Energy commissioned a study of publicly funded oil sands R&D. This present work is the second phase of this study and aims at estimating and evaluating the intent and level of effort of current privately funded oil sands R&D.
Sponsored by the Alberta Department of Energy (ADOE), the Alberta Energy Research Institute (AERI), and by industry partners, the purpose of this study is to document the intent and level of effort of current privately funded oil sands and heavy oil research and technology development. Identifying and documenting current oil sands R&D is supportive of the vision for oil sands in 2020 prepared by the Oil Sands Development Business Unit of ADOE:

“Alberta is a global energy leader, using its world class knowledge, expertise and leadership to develop the vast energy resources of the province and to market these resources and abilities to the world.”

In 2020, Alberta Energy sees Alberta as a world-scale hub for energy and refined products. Alberta would be extracting full value from its oil sands resources and supplying:

- 3.5 million barrels per day (bpd) of bitumen, of which 2 million bpd would be upgraded to synthetic crude oil (SCO);
- 430,000 bpd of conventional crude oil recovered from Alberta fields;
- An additional 300,000 bpd of conventional crude oil from Saskatchewan and the Northwest Territories transiting through Alberta;
- 2.4 million bpd of SCO and conventional crude oil converted into refined petroleum products by Alberta refineries;
- 10 billion cubic feet (bcf) per day of natural gas recovered from Alberta fields;
- An additional 10 bcf per day of natural gas transiting through Alberta in the Mackenzie Delta pipeline and the Alaska pipeline;
- 250,000 bpd of natural gas liquids extracted in Alberta;
- 16 billion pounds annually of petrochemicals; and,
- 40 million tonnes per year of coal

In addition, the province would be generating annually 17,600 megawatt of electricity, of which 2.5 million megawatt hour per year would be exported.

Historically, research and development have played a critical role in the successful development of the energy sector and particularly of the oil sands. Major technologies such as SAGD and CSS have been instrumental in enabling the economic recovery of the resource. Today, several research organizations are focused on developing the next generation of oil sands technologies. In order to develop appropriate policies, it is imperative that the Department of Energy, Oil Sands Development Business Unit have a solid understanding of new technologies being developed and their potential impact on exploration, recovery, production, upgrading, environmental footprint, lease closure and reclamation.
Alberta Energy R&D policy objectives include the promotion of collaboration and cooperation between government, universities and industry, and among different industry participants. In the short term, it aims at eliminating the duplication of efforts. However, the emphasis is on long-term outcomes with the aim to maximize reserves, minimize environmental footprint and maximize return on investment.

In 2005, Alberta Energy introduced the Innovative Energy Technology Program (IETP). This program fosters uptake of new and innovative technologies in order to enhance petroleum resource recovery. This program is applicable to conventional oil, natural gas and oil sands. It offers royalty credits worth $200 million over five years. The program is also designed to assist in addressing the gas over bitumen issue. This important policy initiative underscores the important role that Alberta Energy expects new technologies to play in the future.

In this context, the purpose of the present work is to obtain, analyze and present information about the current situation of oil sands R&D. The results of the 2004 study on publicly funded oil sands R&D will be summarized and integrated. However, most of this work is concerned with estimating and describing the level of efforts and desired outcome for privately funded R&D.

This report will therefore serve as a foundation document to assist Alberta Energy and AERI in setting and updating oil sands R&D policies and strategies of the government of Alberta. The information acquired, analyzed and summarized by this review will support current activities at ADOE and AERI. It will constitute an information resource that will be used to answer key questions about oil sands R&D: (e.g.: How much is being spent on oil sands R&D? Who is funding R&D? Which institutions perform R&D? What are the key R&D targets?)
SCOPE

The results of the 2004 study will be summarized and integrated into the analysis and discussion provided in this report. The 2004 study covered bitumen and heavy oil research and development projects conducted in Canada during the five years from fiscal 1998-1999 to fiscal 2002-2003.

This present study is focused on privately funded bitumen and heavy oil research and development. The primary research conducted for this study obtained information on the level of effort and desired outcomes for such R&D for the five years between 2000 and 2004 inclusive.

Public domain and non-confidential sources of information were privileged in order to permit discussion of the report beyond the government of Alberta, and in particular with industry partners. While confidential interviews were conducted with some oil sands companies, specific information obtained from specific companies, while used in the analysis and in the calculation of averages, is not reproduced in the report.

Documenting current R&D is only one part of this work. In order to discuss questions related to the adequacy of funding levels and the choice of R&D targets, information about future opportunities and challenges offered by oil sands must also be assembled and reported. In fact, these issues will be discussed first in the report because they set the stage for the review of R&D. Specifically, the size and importance of oil sands within an Alberta and a world context will be covered, as well as the key technology challenges that are expected to be faced in the future.

The analysis section maps R&D against the overall needs and challenges of the industry. This will serve to improve understanding of the alignment between technology development and long term oil sands opportunities. It will assist in matching technology with the characteristics of oil sands deposits and in identifying suitable areas for R&D policy initiatives.
A World Class Resource

Alberta oil sands contain the world’s largest reserves of bitumen. The initial volume in place is 1.7 trillion barrels of bitumen, and, based on current technology, the remaining established reserves are 174 billion barrels of bitumen (Alberta Energy and Utilities Board 2005).

The Alberta oil sands are, undoubtedly, a very significant resource by Alberta standards. As noted later in this report, initial volume in place and initial reserves of oil sands dwarf initial volume in place and reserves of conventional oil and natural gas combined.

Alberta oil sands are also very significant by world standards. The Oil and Gas Journal has recognized the reserves methodology of the Energy and Utilities Board (EUB) and has adopted the EUB’s estimate for established reserves of Alberta oil sands. As a result, Canada and Alberta now rank second in the world for oil reserves behind Saudi Arabia.

With new technology and improved economics the potential exists for more of the oil sands to be counted as established reserves. Therefore, it is not out of the realm of possibilities that, one day, Alberta will be recognized as owning the largest oil reserves in the world, surpassing Saudi Arabia. The Alberta oil sands are indeed world-class assets.

Recovery of this vast resource is becoming an increasingly important area of economic activity in the province. Existing mining operations are being expanded, and new mining and in-situ recovery projects are being developed. According to Alberta Economic Development (December 2005), in the 1996 to 2004 period, the oil sands industry spent an estimated CA$29 billion on new projects, plus an estimated CA$4.8 billion on sustaining capital. During 2005 to 2015 period, the Alberta oil sands industry may spend as much as CA$79.5 billion on new facilities and another CA$16.5 billion on sustaining capital (Alberta Economic Development 2005).

In a report published in 2005, the Canadian Energy Research Institute (CERI) assessed the economic impacts of Alberta’s oil sands industry on economies at regional, provincial, national and international levels for the 2000-2020 period. CERI forecasted that oil sands production would reach 3.2 million bpd in 2020. In order to reach this level, the industry would invest $100 billion in capital over the period (all dollar amounts stated in 2004 dollars). In 2020, the industry would spend $46 billion annually in operating expenses. The net effect of the oil sands industry would be to add 3.0% to the Gross Domestic Product (GDP) of Canada in 2020, involving 244,000 permanent jobs in Alberta and 114,000 permanent jobs in other Canadian provinces. Over the period, added government revenues in the form of taxes and royalties would be $42 billion for Alberta, $51 billion for the Federal government and $29 billion for other provinces (Canadian Association of Petroleum Producers 2005; Holly 2005).
Global and United States Petroleum Demand

According to the U.S. Department of Energy, world demand for crude oil is forecasted to grow from 78 million barrels per day (bpd) in 2002 to 103 million bpd in 2015. Most (45%) of the growth is expected to originate from emerging Asian nations, particularly China and India. Current global crude oil supply capability is 80 million bpd. The supply/demand gap expected to be filled by 2015 is 23 million bpd, or an increase of 28% in 10 years (Energy Information Administration 2005).

Historical information for North American petroleum demand is shown on Figure 1. Mirroring global demand, and despite economic cycles, North American petroleum demand is also on a moderate but steady growth path.

![Figure 1 - North American Petroleum Demand](image)

Source: U.S. Department of Energy

In 2005, U.S. petroleum demand was 20.66 million bpd. Imports of 12.35 million bpd satisfied 60% of U.S. demand. By 2015, U.S. petroleum demand is forecasted to increase to 23.53 million bpd and imports to 13.23 million bpd.
**Alberta Oil Sands Supply**

In 2004, approximately 1.1 million bpd of bitumen were recovered from Alberta oil sands. However, because of inherent deficiencies, crude bitumen is difficult to ship and may not be used in large quantities by North American refineries. In 2004, only 400 thousand bpd of bitumen were shipped and sold as diluted bitumen (DilBit) or as bitumen blended in synthetic crude oil (SynBit). The balance of oil sands production was upgraded into approximately 600 thousand bpd of synthetic crude oil (SCO) (Alberta Energy and Utilities Board 2005).

As shown on Table 1, a significant number of new oil sands projects are being planned and constructed. Together they would increase production to 3 to 5 million bpd by 2020. However, this substantial increase, while impressive, will not be sufficient to offset crude oil imports into North America. The combined effect of declining U.S. conventional production and North American demand growth will continue to create a market opportunity for increased oil sands production from Alberta into the United States. Beyond North America, increased oil sands production could also be marketed to satisfy the growing world consumption noted above.

In summary, given current forecasts, the Alberta oil sands industry is facing favourable market demand conditions for its ambitious to increase production by threefold to fivefold by 2020. The implementation of such growth would results in substantial economic benefits for Alberta and for Canada.

The next sections of this report will explore the following points:

- The spectacular growth planned for Alberta oil sands is only based on less than half of the resource. New technology could be developed to unlock the potential of the other half of the oil sands resource.
- Even though the industry is investing massive amounts of capital to construct commercial projects using existing technologies, major technical challenges remain to be solved and their solution will require major technology advances.
<table>
<thead>
<tr>
<th>Location</th>
<th>Technology</th>
<th>Historical</th>
<th>Forecast</th>
<th>Announced Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Albian Sands</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Muskeg River Mine</td>
<td>SAGD</td>
<td>406</td>
<td>486</td>
<td>487</td>
</tr>
<tr>
<td><strong>BlackRock Ventures</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Orion - Hilda Lake</td>
<td>Cold primary</td>
<td>0</td>
<td>60</td>
<td>500</td>
</tr>
<tr>
<td>Chipmunk - Peace River</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seal - Peace River</td>
<td>Cold primary</td>
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<td>807</td>
<td>3,168</td>
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<tr>
<td>BlackRock - Total Oil Sands</td>
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<td>406</td>
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<td>3,715</td>
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<tr>
<td><strong>Canadian Natural Resources Limited</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizon</td>
<td>Surface mining</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep Horizon</td>
<td>SAGD</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cold Lake Bonnyville</td>
<td>Cold primary</td>
<td>60,000</td>
<td>59,000</td>
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<td>Pelican Lake</td>
<td>Cold primary</td>
<td>18,600</td>
<td>29,000</td>
<td>24,000</td>
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<tr>
<td>Primrose; Wolf Lake; Kirby</td>
<td>CSS; Thermal In Situ</td>
<td>30,000</td>
<td>39,000</td>
<td>44,000</td>
</tr>
<tr>
<td>Birch Mountain; Gregoire Lake</td>
<td>Thermal In Situ</td>
<td></td>
<td></td>
<td></td>
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<td>CNRL - Total Oil Sands</td>
<td></td>
<td>108,600</td>
<td>127,000</td>
<td>163,000</td>
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</table>
### Table 1 (Cont’d) - Oil Sands Production (barrels per day)

<table>
<thead>
<tr>
<th>Location</th>
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<th>Announced Potential</th>
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<tr>
<td><strong>Chevron</strong></td>
<td>Muskeg River Mine</td>
<td>See Shell</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Swan Lake</td>
<td>Land acquired March 2006; no other information available.</td>
<td></td>
<td></td>
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<tr>
<td><strong>Connacher Oil &amp; Gas</strong></td>
<td>Great Divide</td>
<td>SAGD</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Conoco Phillips Canada</strong></td>
<td>Surmont (50% Conoco Phillips; 50% Total)</td>
<td>SAGD</td>
<td>12,000</td>
<td>27,000</td>
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<tr>
<td><strong>Deer Creek Energy (100% owned by Total)</strong></td>
<td>Joslyn Creek (84% Deer Creek and 16% Enermark)</td>
<td>SAGD</td>
<td>5,000</td>
<td>25,000</td>
</tr>
<tr>
<td></td>
<td>Joslyn Creek (84% Deer Creek and 16% Enermark)</td>
<td>Surface mining</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deer Creek - Total Oil Sands</td>
<td></td>
<td></td>
<td></td>
<td>5,000</td>
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Table 1 (Cont’d) - Oil Sands Production (barrels per day)

<table>
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<th>Location</th>
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<th>Announced Potential</th>
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<tr>
<td>Devon</td>
<td>Dover</td>
<td>SAGD</td>
<td>1,400</td>
<td>1,400</td>
</tr>
<tr>
<td></td>
<td>Jackfish</td>
<td>SAGD</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Devon - Total Oil Sands</td>
<td>1,400</td>
<td>1,400</td>
<td>1,400</td>
</tr>
<tr>
<td>EnCana</td>
<td>Pelican Lake</td>
<td>Cold primary</td>
<td>13,739</td>
<td>18,900</td>
</tr>
<tr>
<td></td>
<td>Foster Creek</td>
<td>SAGD</td>
<td>13,026</td>
<td>28,774</td>
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<td></td>
<td>Christina Lake</td>
<td>SAGD</td>
<td>0</td>
<td>5,300</td>
</tr>
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<td></td>
<td>Borealis</td>
<td>In Situ</td>
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<td></td>
</tr>
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<td></td>
<td>EnCana - Total Oil Sands</td>
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<td>52,974</td>
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<td>Fort MacKay First Nation</td>
<td>Surface mining</td>
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<td></td>
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<tr>
<td>Husky Energy</td>
<td>Sunrise</td>
<td>SAGD</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tucker</td>
<td>SAGD</td>
<td></td>
<td></td>
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<td></td>
<td>Husky - Total Oil Sands</td>
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<td>0</td>
<td>0</td>
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<tr>
<td>Imperial Oil</td>
<td>Cold Lake</td>
<td>CSS</td>
<td>119,000</td>
<td>112,000</td>
</tr>
<tr>
<td></td>
<td>Kearl</td>
<td>Surface mining</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Imperial Oil - Total Oil Sands</td>
<td>119,000</td>
<td>112,000</td>
<td>126,000</td>
</tr>
<tr>
<td>Location</td>
<td>Technology</td>
<td>Historical</td>
<td>Forecast</td>
<td>Announced Potential</td>
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<tr>
<td>------------------------</td>
<td>------------</td>
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<td>----------</td>
<td>---------------------</td>
</tr>
<tr>
<td>JACOS</td>
<td>Hangingstone</td>
<td>SAGD</td>
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<td>2,200</td>
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<td>MEG Energy (partially owned by CNOOC)</td>
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<td>SAGD</td>
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<tr>
<td>Nexen</td>
<td>Long Lake (50% Nexen; 50% OPTI)</td>
<td>SAGD</td>
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<tr>
<td>OPTI Canada</td>
<td>Long Lake</td>
<td>See Nexen</td>
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<td>Paramount Resources</td>
<td>Leismer</td>
<td>SAGD</td>
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<td></td>
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<td>Petrobank</td>
<td>Whitesands</td>
<td>THAI</td>
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</tr>
<tr>
<td>Location</td>
<td>Technology</td>
<td>Historical</td>
<td>Forecast</td>
<td>Announced Potential</td>
</tr>
<tr>
<td>----------</td>
<td>------------</td>
<td>------------</td>
<td>----------</td>
<td>----------------------</td>
</tr>
<tr>
<td>MacKay River</td>
<td>SAGD</td>
<td>0</td>
<td>9,400</td>
<td>16,600</td>
</tr>
<tr>
<td>Fort Hills (55% Petro-Canada; 30% UTS Energy; 15% Teck Cominco)</td>
<td>Surface mining</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Dover, Meadow Creek, Lewis and Chard</td>
<td>In Situ</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Petro-Canada - Total Oil Sands</td>
<td></td>
<td>0</td>
<td>9,400</td>
<td>16,600</td>
</tr>
<tr>
<td>Muskeg River Mine (60% Shell; 20% Chevron; 20% Western Oil Sands)</td>
<td>Surface mining</td>
<td>0</td>
<td>0</td>
<td>135,500</td>
</tr>
<tr>
<td>Jackpine Mine</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peace River</td>
<td>Horizontal CSS</td>
<td>4,200</td>
<td>8,900</td>
<td>8,100</td>
</tr>
<tr>
<td>Shell - Total Oil Sands</td>
<td></td>
<td>4,200</td>
<td>8,900</td>
<td>143,600</td>
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</table>
### Table 1 (Cont’d) - Oil Sands Production (barrels per day)

<table>
<thead>
<tr>
<th>Location</th>
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<th>Historical</th>
<th>Forecast</th>
<th>Announced Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Suncor Energy</strong></td>
<td>Surface Mine</td>
<td>Surface mining</td>
<td>113,900</td>
<td>205,800</td>
</tr>
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<td></td>
<td>Firebag</td>
<td>SAGD</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Suncor - Total Oil Sands</td>
<td>Surface mining</td>
<td>113,900</td>
<td>205,800</td>
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<td><strong>Syncrude</strong></td>
<td>Athabasca</td>
<td>Surface mining</td>
<td>204,658</td>
<td>227,808</td>
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<tr>
<td><strong>Synenco Energy</strong></td>
<td>Northern Lights (60% Synenco; 40% Sinopec)</td>
<td>Surface mining</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>Surmont</td>
<td>See ConocoPhillips</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Joslyn</td>
<td>See Deer Creek</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>UTS Energy</strong></td>
<td>Fort Hills</td>
<td>See Petro-Canada</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Western Oil Sands</strong></td>
<td>Muskeg River Mine</td>
<td>See Shell</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL (All companies)</strong></td>
<td></td>
<td>552,964</td>
<td>722,566</td>
<td>982,593</td>
</tr>
</tbody>
</table>

Source: Portfire Associates from company public information
RESOURCE DESCRIPTION

Introduction

In this section, an overview of Alberta bitumen resources will be provided. In order to set the appropriate context, the review will start by considering all Alberta oil and gas resources: conventional oil, natural gas and bitumen. It is instructive to place bitumen within the perspective of the oil and gas industry in this province, which has been primarily based on conventional resources.

A detailed description of bitumen resources will follow. It needs to be emphasized that not all bitumen deposits are similar. Indeed, there are vast differences from rich thick channel oil sands with a potential recovery factor of up to 60% when using SAGD and 90% with surface mining, to other, almost forgotten but nonetheless significant deposits with a present recovery factor of zero. An area of focus for the study is to convey a better understanding of the size and characteristics of bitumen deposits that are currently unrecoverable because some of these deposits may be attractive targets for long-term R&D.

Terminology

When discussing fossil resources, the terminology used by the EUB will be the used in this report.

Volume in place is the quantity of resources calculated or interpreted to exist in a reservoir. These volumes are specifically proven by drilling, testing or production. They also include the portion of contiguous resources that are interpreted to exist from geological, geophysical or similar information with reasonable certainty.

Established reserves are the fraction of volume in place that is recoverable on the basis of current technology and present and anticipated economic conditions. Established reserves are calculated by applying a recovery factor to volume in place.

Initial volume in place and initial established reserves are the quantities before any volume has been produced from the reservoir. Remaining volume in place and remaining established reserves are the initial quantities less cumulative production.

Ultimate recoverable potential is an estimate of initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased. Ultimate recoverable potential includes initial established reserves and adds an estimate of future additions, extension and revisions to existing deposits and the discovery of new deposits. Discovered resources are those that have been confirmed by wells drilled while undiscovered resources are expected to be discovered by future drilling. Another way to think of the term ultimate recoverable potential is as an estimate of the volume of initial established reserves that will be proven to exist after exploration has ceased.

Ultimate volume in place applied the same concept to initial volume in place.
The Recovery Factor

In this project, there are two distinct concepts with respect to the recovery factor of bitumen and heavy oil resources.

The first concept pertains to whether a recovery factor exists or not. Deposits for which there is at least one applicable commercial recovery technology are deemed recoverable and therefore have a recovery factor assigned to them. Therefore, a fraction of these deposits is counted as reserves. In other words, the recovery factor for these reservoirs is greater than zero. Conversely, there are deposits for which there is no applicable commercial recovery technology. Those deposits have a recovery factor of zero. Here, the purpose of R&D is to target deposits with no recovery factor and to develop a recovery technology.

The second concept relates to the fact that existing recovery technology only recovers a fraction of the initial in-place volume. Therefore, after the completion of the initial recovery technology, there is an amount of bitumen left behind. Generally, this amount is substantial. Here, the purpose of technology development is to increase the recovery factor by either increasing the recovery factor of the initial recovery technology or by following-up with at least a second, complementary, recovery technology.

Ultimate Potential

Ultimate potential represents an estimate of the future potential of each resource. Table 2 (metric units) and Table 3 (Imperial units) presents ultimate potential numbers for crude bitumen, conventional crude oil (light, medium and heavy combined) and natural gas.

| Table 2 - Ultimate Potential of Oil & Gas Resources  
(Metric Units) |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Crude Bitumen</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(billion m³)</td>
<td>Conventional</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Crude Oil</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(billion m³)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ultimate Volume In Place</td>
<td>400</td>
<td>12</td>
</tr>
<tr>
<td>Ultimate Recoverable Potential</td>
<td>50</td>
<td>3.1</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane
Natural gas numbers include estimates for conventional natural gas and coal bed methane. While there is a long history and large amounts of data for conventional natural gas, only a small portion of coal resources has been studied in detail. Nevertheless, the EUB estimates that there is some 14,000 billion m$^3$ (500 trillion cubic feet) of gas in place within all of the coal in Alberta. However, currently CBM has a very low recovery factor of less than 0.01% and initial established reserves of 8.176 billion m$^3$.

In order to compare oil and gas resources, it is customary to convert natural gas amounts into equivalent oil amounts on the basis of equivalent energy content. Tables 4 and 5 re-state ultimate potential on the basis of equivalent energy content. It is important to note that, despite the huge potential offered by coal bed methane, the potential presented by oil sands is at least 10 times larger. Figures 2 and 3 illustrate the relative ultimate potential, on the basis of ultimate volume in place and ultimate recoverable potential of the three major oil and gas resources in Alberta. Oil sands unquestionably offer the largest potential.
Table 4 - Ultimate Potential of Oil & Gas Resources
(Equivalent Metric Units)

<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen (billion m³)</th>
<th>Crude Oil (billion m³)</th>
<th>Natural Gas (equivalent billion m³)</th>
<th>Total (equivalent billion m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ultimate Volume In Place</td>
<td>400</td>
<td>12</td>
<td>23</td>
<td>435</td>
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<tr>
<td>Ultimate Recoverable Potential</td>
<td>50</td>
<td>3.1</td>
<td>6</td>
<td>59</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane
Note: 1 m³ crude oil = 1068 m³ natural gas
Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)

Table 5 - Ultimate Potential of Oil & Gas Resources
(Equivalent Imperial Units)

<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen (billion barrels)</th>
<th>Crude Oil (billion barrels)</th>
<th>Natural Gas (billion equivalent barrels)</th>
<th>Total (billion equivalent barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ultimate Volume In Place</td>
<td>2,517</td>
<td>73</td>
<td>145</td>
<td>2,735</td>
</tr>
<tr>
<td>Ultimate Recoverable Potential</td>
<td>315</td>
<td>20</td>
<td>37</td>
<td>371</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane
Note: 1 barrel crude oil = 6.02 thousand cubic feet of natural gas
Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)

Volume In Place and Established Reserves of Oil & Gas Resources

Ultimate potential attempts to include future events and less explored resources. Volume in place and established reserves are solely based on actual wells drilled, tests and production. Tables 6 and 7 present details for bitumen, conventional oil and natural gas.

The tables first indicate the current estimates of initial volume in place. This is the volume of the resource calculated to be in the ground before any extraction. Recovery factors are applied to initial volumes in place to convert them into initial established...
reserves. The recovery factors reflect estimates of how much of the resource in the ground can be brought to the surface and produced, on the basis of current technology and current and anticipated economic factors. Recovery factors vary from zero for some bitumen deposits to as high as 70% for some attractive natural gas pools. Cumulative production is the total quantity produced from the very beginning until today. Cumulative production is subtracted from initial established reserves to yield remaining established reserves, which is the remaining amount that can be economically produced using current technologies.

**Figure 2 – Oil & Gas Resources**

Percent of Ultimate Volume In Place

- **Crude Bitumen**: 92%
- **Natural Gas**: 5%
- **Crude Oil**: 3%

Note: Includes coal bed methane
The 2004 annual production is stated in order to calculate a reserve index, which is an indicator of the remaining economic life of the resource. The reserve index is calculated by dividing remaining established reserves by the most recent annual production. It is important to understand that while the reserve index is expressed in terms of years, it does not mean that all production will cease when that time is up. In the future, new exploration drilling, technology advances and improved economics are likely to cause additions to reserve numbers. At the same time, in a mature basin, annual production will also slowly decline, thereby prolonging the life of the basin, albeit at a reduced level of activity.

When cumulative production (historical production) and remaining established reserves (future production) are subtracted from initial volume in place, the resulting number is the quantity of the resource that will be left in the ground after all production activities have ceased, assuming current technology and current and anticipated economic
It is important to note that the quantities that are currently deemed to be unrecoverable are substantial.

Table 6 – Oil & Gas Resources Volume In Place and Reserves
(Metric Units)

<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen (billion m³)</th>
<th>Conventional Crude Oil (billion m³)</th>
<th>Natural Gas (billion m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Volume In Place</td>
<td>269.95</td>
<td>10.00</td>
<td>7,910</td>
</tr>
<tr>
<td>Initial Established Reserves</td>
<td>28.39</td>
<td>2.67</td>
<td>4,555</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>0.73</td>
<td>2.42</td>
<td>3,420</td>
</tr>
<tr>
<td>Remaining Established Reserves</td>
<td>27.66</td>
<td>0.25</td>
<td>1,134</td>
</tr>
<tr>
<td>2004 Annual Production</td>
<td>0.0634</td>
<td>0.035</td>
<td>137</td>
</tr>
<tr>
<td>Reserve Index (years)</td>
<td>436</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>Currently Unrecoverable</td>
<td>241.55</td>
<td>7.34</td>
<td>3,356</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane
Source: (Alberta Energy and Utilities Board 2005)
Table 7 – Oil & Gas Resources Volume In Place and Reserves
(Imperial Units)

<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen (billion barrels)</th>
<th>Conventional Crude Oil (billion barrels)</th>
<th>Natural Gas (trillion cubic feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Volume In Place</td>
<td>1,698.7</td>
<td>62.9</td>
<td>277.0</td>
</tr>
<tr>
<td>Initial Established Reserves</td>
<td>178.7</td>
<td>16.8</td>
<td>161.0</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>4.6</td>
<td>15.2</td>
<td>121.0</td>
</tr>
<tr>
<td>Remaining Established Reserves</td>
<td>174.1</td>
<td>1.6</td>
<td>40.0</td>
</tr>
<tr>
<td>2004 Annual Production</td>
<td>0.40</td>
<td>0.22</td>
<td>4.9</td>
</tr>
<tr>
<td>Reserve Index (years)</td>
<td>436</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>Currently Unrecoverable</td>
<td>1,520.1</td>
<td>46.2</td>
<td>116.0</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane
Source: (Alberta Energy and Utilities Board 2005)

As noted earlier, in order to compare oil to natural gas, volumes of natural gas must be converted into equivalent units, based on equivalent energy content. Tables 8 and 9 restate the numbers shown on the two previous tables but the amounts for natural gas have been converted into equivalent energy units.

The key message from this analysis is that bitumen is by far a larger resource that conventional oil and natural gas. As illustrated by Figures 4, 5 and 6, while bitumen represents only 28% of 2004 oil and gas production on an equivalent energy basis, bitumen resources account for 95% of remaining established reserves and 96% of resources currently unrecoverable.
### Table 8 – Oil & Gas Resources Volume In Place and Reserves

(Equivalent Metric Units)

<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen (billion m3)</th>
<th>Crude Oil (billion m3)</th>
<th>Natural Gas (equivalent billion m3)</th>
<th>Total (equivalent billion m3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Volume In Place</td>
<td>269.95</td>
<td>10.00</td>
<td>7.41</td>
<td>287.35</td>
</tr>
<tr>
<td>Initial Established Reserves</td>
<td>28.39</td>
<td>2.67</td>
<td>4.26</td>
<td>35.32</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>0.73</td>
<td>2.42</td>
<td>3.20</td>
<td>6.35</td>
</tr>
<tr>
<td>Remaining Established Reserves</td>
<td>27.66</td>
<td>0.25</td>
<td>1.06</td>
<td>28.97</td>
</tr>
<tr>
<td>Percent Remaining Established Reserves</td>
<td>95.5%</td>
<td>0.9%</td>
<td>3.7%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2004 Annual Production</td>
<td>0.0634</td>
<td>0.035</td>
<td>0.128</td>
<td>0.227</td>
</tr>
<tr>
<td>Percent Annual Production</td>
<td>28.0%</td>
<td>15.4%</td>
<td>56.6%</td>
<td>100.0%</td>
</tr>
<tr>
<td>Reserve Index (years)</td>
<td>436</td>
<td>7</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Currently Unrecoverable</td>
<td>241.55</td>
<td>7.34</td>
<td>3.14</td>
<td>252.03</td>
</tr>
<tr>
<td>Percent Currently Unrecoverable</td>
<td>95.8%</td>
<td>2.9%</td>
<td>1.2%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane
Note: 1 m3 crude oil = 1068 m3 natural gas
Source: (Alberta Energy and Utilities Board 2005)
<table>
<thead>
<tr>
<th></th>
<th>Crude Bitumen (billion barrels)</th>
<th>Crude Oil (billion barrels)</th>
<th>Natural Gas (billion equivalent barrels)</th>
<th>Total (billion equivalent barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Volume In Place</td>
<td>1,698.7</td>
<td>62.9</td>
<td>46.6</td>
<td>1,808.3</td>
</tr>
<tr>
<td>Initial Established Reserves</td>
<td>178.7</td>
<td>16.8</td>
<td>26.8</td>
<td>222.3</td>
</tr>
<tr>
<td>Cumulative Production</td>
<td>4.6</td>
<td>15.2</td>
<td>20.1</td>
<td>39.9</td>
</tr>
<tr>
<td>Remaining Established Reserves</td>
<td>174.1</td>
<td>1.6</td>
<td>6.7</td>
<td>182.3</td>
</tr>
<tr>
<td>Percent Remaining Established Reserves</td>
<td>95.5%</td>
<td>0.9%</td>
<td>3.7%</td>
<td>100.0%</td>
</tr>
<tr>
<td>2004 Annual Production</td>
<td>0.40</td>
<td>0.22</td>
<td>0.81</td>
<td>1.43</td>
</tr>
<tr>
<td>Percent Annual Production</td>
<td>28.0%</td>
<td>15.4%</td>
<td>56.6%</td>
<td>100.0%</td>
</tr>
<tr>
<td>Reserve Index (years)</td>
<td>436</td>
<td>7</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Currently Unrecoverable</td>
<td>1,520.1</td>
<td>46.2</td>
<td>19.8</td>
<td>1,586.0</td>
</tr>
<tr>
<td>Percent Currently Unrecoverable</td>
<td>95.8%</td>
<td>2.9%</td>
<td>1.2%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Note: Includes coal bed methane  
Note: 1 m³ crude oil = 6.2929 barrel crude oil  
Source: (Alberta Energy and Utilities Board 2005)
Figure 4 – Oil & Gas Resources
Percent of 2004 Annual Production

- Natural Gas: 57%
- Crude Bitumen: 28%
- Crude Oil: 15%

Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)
Figure 5 – Oil & Gas Resources
Percent of Remaining Established Reserves

- Crude Bitumen: 95%
- Natural Gas: 4%
- Crude Oil: 1%

Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)
Figure 6 – Oil & Gas Resources
Percent of Currently Unrecoverable Volume In Place

- Crude Bitumen: 96%
- Crude Oil: 3%
- Natural Gas: 1%

Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)
**Volume In Place and Established Reserves of Oil Resources**

**Conventional Oil**

Historically the Alberta oil industry was built on conventional light and medium oil. Later, technology was developed to economically recover conventional heavy oil which is now considered to be a mature segment of the industry. More recently, oil sands were developed starting with surface mining and followed in the last few years by in situ developments.

Tables 10 and 11 present details of volume in place and reserves for bitumen, conventional light and medium oil and conventional heavy oil. The largest quantities of volume in place and remaining established reserves belong to bitumen followed by conventional light and medium oil and thirdly by conventional heavy oil. However, Alberta's past is reflected in the relatively high number for cumulative production of conventional light and medium oil which by far exceeds cumulative production for either bitumen or conventional heavy oil. This however must be contrasted with the reserve index of conventional oil as compared to bitumen. Using the most recent annual production information, reserve indices of 8 and 6 years can be calculated for conventional light and medium oil and for conventional heavy oil respectively on the basis of their remaining established reserves. By contrast, the reserve index for bitumen is 436 years. However, it must be recognized that bitumen production is a recent development and that a considerable number of new oil sands projects are presently being constructed and will result in a significant increase to bitumen production in the near future. Should bitumen production increase to the level of 3 million barrels per day, the reserve index becomes 159 years on the basis of the current estimate for remaining established reserves. Should bitumen production reach to 5 million barrels per day as called for in the vision of the Oil Sands Technology Roadmap, the reserve index still stands as a respectable 95 years (Alberta Chamber of Resources 2004). The key message therefore is that Alberta's bitumen reserves are substantial and are likely to sustain an oil sands industry for at least the next century.

Figures 7 to 14 illustrate some of the key numbers presented in tables 10 and 11. Figures 7 and 8 present the vital signs for conventional light and medium oil and conventional heavy oil. Conventional light and medium oil is a two times larger segment than conventional heavy oil as measured by the current level of production and by remaining established reserves.

Figures 9 and 10 illustrate the opportunity presented by conventional oil. As clearly indicated in the 2003 PTAC report entitled "Spudding Innovation" there is a relatively large quantity of oil that is destined to remain in the ground after all conventional production has ceased, given current technologies. These amounts are shown on Figures 9 and 10 as the section labelled “Currently not recoverable with commercial technologies”. If the industry and the governments do not innovate, the continued use of current technologies will leave in the ground 71% of the initial volume in place for conventional light and medium oil and 82% of the initial volume in place of conventional heavy oil.
One of the key recommendations of Spudding Innovation was the creation of a detailed business case for increased oil and gas recovery through R&D, demonstration and commercialization. The specific Alberta goals identified were additional recoverable reserves of 5 billion barrels of conventional oil and 25 TCF of conventional natural gas by 2015 attributable to new R&D. As discussed in “Spudding Innovation”, a one-point improvement in the recovery of conventional oil is equivalent to about 600 million barrels of oil, or about $22 billion in production revenues and $2.2 billion in royalties.

In response to Spudding Innovation, the Alberta Department of Energy announced the $200 million Innovative Energy Technologies Program (IETP). In addition, the government of Alberta, through AERI, in partnership with industry have funded the $840,000 PTAC business case project which is due to report in 2006.

**Bitumen**

While the opportunity has been identified and is being acted upon for conventional oil, bitumen offers a similar, if not more compelling opportunity.

Figures 11 and 12 graphically represent the vital signs for oil sands. It is immediately apparent that oil sands are a recent but highly promising sector. Annual production and cumulative production are very small as compared to remaining established reserves and initial volume in place. Figures 13 and 14 illustrate the opportunity presented by oil sands in the context of the opportunity described earlier for conventional oil. The continued use of current technologies would leave behind 89% of bitumen volume in place after all recovery activities cease. The amount of bitumen that is currently not recoverable with commercial technologies is 241 billion m³. This amount is over 30 times larger than the volume not currently recoverable of conventional light, medium and heavy oil combined. Therefore, oil sands not only present a substantial economic opportunity in the present using existing commercial technologies but also an even larger opportunity for the future.

**The Future Is Oil Sands**

The oil and gas sector has been a significant contributor to the Alberta economy. Royalties on conventional oil and natural gas have enriched government revenues and have been instrumental in producing annual surpluses and in eliminating the accumulated debt. However, conventional oil production is clearly in decline in Alberta and conventional natural gas production is at a plateau and will be in a clear decline in coming years. Conventional oil and gas are part of Alberta’s past. The future, however, is oil sands. Remaining established reserves of bitumen are approximately 25 times remaining established reserves of conventional oil including heavy oil. Oil sands production is currently at approximately one million barrels per day but it is expected to increase to 3 to 5 million barrels per day in the next 10 to 15 years. Even at this rate, oil sands established reserve will last for at least 100 years.
<table>
<thead>
<tr>
<th></th>
<th>Initial Volume In Place (billion m³)</th>
<th>Cumulative Production (billion m³)</th>
<th>Remaining Established Reserves (billion m³)</th>
<th>2004 Annual Production (billion m³)</th>
<th>Currently Not Recoverable with Commercial Technologies (billion m³)</th>
<th>Percent Not Recoverable (billion m³)</th>
<th>Reserve Index (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bitumen</td>
<td>269.95</td>
<td>0.73</td>
<td>27.66</td>
<td>0.063</td>
<td>241.55</td>
<td>89.5%</td>
<td>436</td>
</tr>
<tr>
<td>Conventional Light Medium Oil</td>
<td>7.86</td>
<td>2.11</td>
<td>0.18</td>
<td>0.023</td>
<td>5.57</td>
<td>70.9%</td>
<td>8</td>
</tr>
<tr>
<td>Conventional Heavy Oil</td>
<td>2.14</td>
<td>0.31</td>
<td>0.07</td>
<td>0.012</td>
<td>1.76</td>
<td>82.3%</td>
<td>6</td>
</tr>
</tbody>
</table>
## Table 11 - Oil Resources Volume In Place and Reserves
(Imperial Units)

<table>
<thead>
<tr>
<th></th>
<th>Initial Volume In Place (billion barrels)</th>
<th>Cumulative Production (billion barrels)</th>
<th>Remaining Established Reserves (billion barrels)</th>
<th>2004 Annual Production (billion barrels)</th>
<th>Currently Not Recoverable with Commercial Technologies (billion barrels)</th>
<th>Percent Not Recoverable (billion barrels)</th>
<th>Reserve Index (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bitumen</td>
<td>1698.7</td>
<td>4.6</td>
<td>174.1</td>
<td>0.396</td>
<td>1520.1</td>
<td>89.5%</td>
<td>436</td>
</tr>
<tr>
<td>Conventional Light Medium Oil</td>
<td>49.4</td>
<td>13.2</td>
<td>1.1</td>
<td>0.147</td>
<td>35.1</td>
<td>70.9%</td>
<td>8</td>
</tr>
<tr>
<td>Conventional Heavy Oil</td>
<td>13.5</td>
<td>2.0</td>
<td>0.4</td>
<td>0.077</td>
<td>11.1</td>
<td>82.3%</td>
<td>6</td>
</tr>
</tbody>
</table>
Figure 7 - Conventional Oil Resources (Metric Units)

- **Annual Production**
- **Remaining Established Reserves**
- **Cumulative Production**
- **Initial Volume In Place**

**Conventional heavy oil**
- Initial Volume In Place: 2.14 billion m³
- Annual Production: 0.07 billion m³
- Remaining Established Reserves: 0.012 billion m³
- Cumulative Production: 0.31 billion m³

**Conventional light medium oil**
- Initial Volume In Place: 7.86 billion m³
- Annual Production: 0.023 billion m³
- Remaining Established Reserves: 0.018 billion m³
- Cumulative Production: 2.11 billion m³

Source: (Alberta Energy and Utilities Board 2005)
Figure 8 - Conventional Oil Resources
(Imperial Units)

Source: (Alberta Energy and Utilities Board 2005)
Figure 9 - Conventional Oil Resources
Unrecoverable Volume In Place (Metric Units)

Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)
Figure 10 - Conventional Oil Resources
Unrecoverable Volume In Place (Imperial Units)

<table>
<thead>
<tr>
<th>Type</th>
<th>Cumulative Production</th>
<th>Remaining Established Reserves</th>
<th>Currently Not Recoverable with Commercial Technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional heavy oil</td>
<td>2.0</td>
<td>0.4</td>
<td>11.1</td>
</tr>
<tr>
<td>Conventional light medium oil</td>
<td>13.2</td>
<td>1.1</td>
<td>35.1</td>
</tr>
</tbody>
</table>

Initial Volume In Place:
- Conventional heavy oil: 13.5 billion barrels
- Conventional light medium oil: 49.4 billion barrels

Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)
Figure 11 - Bitumen Resources
(Metric Units)

- Annual Production
- Remaining Established Reserves
- Cumulative Production
- Initial Volume In Place

Source: (Alberta Energy and Utilities Board 2005)
Figure 12 - Bitumen Resources
(Imperial Units)

Source: (Alberta Energy and Utilities Board 2005)
**Figure 13 - Bitumen Resources**
**Unrecoverable Volume In Place** (Metric Units)

- **Conventional Light, Medium and Heavy Oil**
  - Initial Volume In Place: 10.00 billion m³
  - Accessible Deposits: 117.0 billion m³
  - Deposits with No Recovery Factor: 152.9 billion m³

- **Bitumen**
  - Initial Volume In Place: 269.9 billion m³
  - Remaining Established Reserves: 0.73 billion m³
  - Currently Not Recoverable with Commercial Technologies: 27.66 billion m³
  - Cumulative Production: 2.42 billion m³

Source: (Alberta Energy and Utilities Board 2005)
Figure 14 - Bitumen Resources
Unrecoverable Volume In Place (Imperial Units)

Source: (Alberta Energy and Utilities Board 2005)
Overview of Bitumen Deposits

Alberta oil sands contain the world largest reserves of bitumen. However, Alberta's bitumen resource is not a uniform resource. There are significant differences between regions and between geological zones. In fact, the quality of bitumen deposits spans a range from highly attractive reservoirs to deposits that have been nearly forgotten.

While conventional crude oil flows naturally or is pumped from the ground, oil sands recovery presents significant technical challenges because of the high viscosity and the low API density of bitumen. Deposits must be mined or recovered using thermal in situ methods. Rich and thick oil sands are highly attractive and are the foundation for the current build up of oil sands projects in Athabasca. Recovery factors for high-quality reservoirs can reach as high as 60% for SAGD and 90% for surface mining. By contrast, some very large bitumen deposits have presently recovery factors of zero.

In this section, an overview of Alberta's bitumen resources is provided from the point of view of compatibility with current commercial recovery technologies.

As shown on Tables 12 and 13, bitumen deposits are found in three regions of Alberta: Athabasca, Cold Lake and Peace River. Athabasca is by far the largest region holding 80% of bitumen volume in place. Athabasca is also the only region where surface mineable deposits are found. The second largest region is Cold Lake. Peace River is the smallest and least developed oil sands region.

For the purpose of this study, the deposits that are exploitable using existing commercial technologies were classified under one of three categories:

- Economically recoverable by Steam-Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS) or equivalent thermal technology
- Economically recoverable by surface mining
- Capable of cold primary production.

The total of all deposits recoverable with existing commercial technologies represent 43% of the Alberta oil sand resources. The balance, or 57%, is currently deemed not recoverable with existing commercial technologies and has an assigned recovery factor of zero. Details about deposits with no recovery factor are also provided on Tables 12 and 13. These deposits were classified into one of the following categories:

- Bitumen in carbonate formations
- Deposits too thin for commercial thermal processes
- Deposits with insufficient cap rock, shale or clay barrier
- Deposits too deep for surface mining but too shallow for SAGD
- Deposits in communication with low pressure gas cap (e.g.: Liege, Ells, Tar and Saleski)

By far, the two largest categories of deposits with no recovery factor are bitumen in carbonate formations and thin oil sands. Together, they represent 50% of the total
Alberta bitumen resources. The relative importance of deposits deemed not recoverable with existing commercial technologies is illustrated on Figure 15.

Each category will be discussed in details in the following sections of this report.

<table>
<thead>
<tr>
<th>Deposit Type (billion m$^3$)</th>
<th>Athabasca</th>
<th>Cold Lake</th>
<th>Peace River</th>
<th>TOTAL</th>
<th>Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Deposits Accessible to Existing Commercial Technologies</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economically recoverable by SAGD, CSS or equivalent commercial thermal technologies</td>
<td>66.8</td>
<td>8.1</td>
<td>8.6</td>
<td>83.5</td>
<td>30.9%</td>
</tr>
<tr>
<td>Economically recoverable by surface mining</td>
<td>9.4</td>
<td>0.0</td>
<td>0.0</td>
<td>9.4</td>
<td>3.5%</td>
</tr>
<tr>
<td>Capable of cold primary production</td>
<td>2.0</td>
<td>22.0</td>
<td>0.06</td>
<td>24.1</td>
<td>8.9%</td>
</tr>
<tr>
<td><strong>TOTAL - Accessible Deposits</strong></td>
<td>78.2</td>
<td>30.1</td>
<td>8.7</td>
<td>117.0</td>
<td>43.3%</td>
</tr>
<tr>
<td><strong>Deposits with No Recovery Factor</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bitumen in carbonate formations</td>
<td>60.8</td>
<td>0.0</td>
<td>10.3</td>
<td>71.1</td>
<td>26.4%</td>
</tr>
<tr>
<td>Too thin for commercial thermal processes</td>
<td>60.4</td>
<td>3.4</td>
<td>1.3</td>
<td>65.1</td>
<td>24.1%</td>
</tr>
<tr>
<td>Deposits with insufficient cap rock, shale or clay barrier</td>
<td>5.8</td>
<td>0.0</td>
<td>0.0</td>
<td>5.8</td>
<td>2.1%</td>
</tr>
<tr>
<td>Too deep for surface mining but too shallow for SAGD</td>
<td>4.4</td>
<td>0.0</td>
<td>0.0</td>
<td>4.4</td>
<td>1.6%</td>
</tr>
<tr>
<td>Deposits in communication with low pressure gas cap (e.g.: Liege, Ells, Tar and Saleski)</td>
<td>2.2</td>
<td>0.0</td>
<td>0.0</td>
<td>2.2</td>
<td>0.8%</td>
</tr>
<tr>
<td>Others</td>
<td>5.7</td>
<td>-1.6</td>
<td>0.2</td>
<td>4.3</td>
<td>1.6%</td>
</tr>
<tr>
<td><strong>TOTAL - Deposits with No Recovery Factor</strong></td>
<td>139.3</td>
<td>1.8</td>
<td>11.8</td>
<td>152.9</td>
<td>56.7%</td>
</tr>
<tr>
<td><strong>TOTAL - All Deposits</strong></td>
<td>217.5</td>
<td>31.9</td>
<td>20.5</td>
<td>269.9</td>
<td>100.0%</td>
</tr>
<tr>
<td>Deposit Type (billion m³)</td>
<td>Athabasca</td>
<td>Cold Lake</td>
<td>Peace River</td>
<td>TOTAL</td>
<td>Percent</td>
</tr>
<tr>
<td>--------------------------</td>
<td>-----------</td>
<td>-----------</td>
<td>------------</td>
<td>-------</td>
<td>---------</td>
</tr>
<tr>
<td><strong>Deposits Accessible to Existing Commercial Technologies</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economically recoverable by SAGD, CSS or equivalent commercial thermal technologies</td>
<td>420.4</td>
<td>51.0</td>
<td>54.1</td>
<td>525.5</td>
<td>30.9%</td>
</tr>
<tr>
<td>Economically recoverable by surface mining</td>
<td>59.2</td>
<td>0.0</td>
<td>0.0</td>
<td>59.2</td>
<td>3.5%</td>
</tr>
<tr>
<td>Capable of cold primary production</td>
<td>12.6</td>
<td>138.4</td>
<td>0.4</td>
<td>151.4</td>
<td>8.9%</td>
</tr>
<tr>
<td><strong>TOTAL - Accessible Deposits</strong></td>
<td>492.1</td>
<td>189.4</td>
<td>54.5</td>
<td>736.0</td>
<td>43.3%</td>
</tr>
<tr>
<td><strong>Deposits with No Recovery Factor</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bitumen in carbonate formations</td>
<td>382.8</td>
<td>0.0</td>
<td>64.9</td>
<td>447.7</td>
<td>26.4%</td>
</tr>
<tr>
<td>Too thin for commercial thermal processes</td>
<td>380.1</td>
<td>21.4</td>
<td>8.2</td>
<td>409.7</td>
<td>24.1%</td>
</tr>
<tr>
<td>Deposits with insufficient cap rock, shale or clay barrier</td>
<td>36.5</td>
<td>0.0</td>
<td>0.0</td>
<td>36.5</td>
<td>2.1%</td>
</tr>
<tr>
<td>Too deep for surface mining but too shallow for SAGD</td>
<td>27.7</td>
<td>0.0</td>
<td>0.0</td>
<td>27.7</td>
<td>1.6%</td>
</tr>
<tr>
<td>Deposits in communication with low pressure gas cap (e.g.: Liege, Ells, Tar and Saleski)</td>
<td>13.8</td>
<td>0.0</td>
<td>0.0</td>
<td>13.8</td>
<td>0.8%</td>
</tr>
<tr>
<td>Others</td>
<td>35.9</td>
<td>-10.1</td>
<td>1.3</td>
<td>27.1</td>
<td>1.6%</td>
</tr>
<tr>
<td><strong>TOTAL - Deposits with No Recovery Factor</strong></td>
<td>876.8</td>
<td>11.3</td>
<td>74.3</td>
<td>962.4</td>
<td>56.7%</td>
</tr>
<tr>
<td><strong>TOTAL - All Deposits</strong></td>
<td>1,368.9</td>
<td>200.7</td>
<td>128.8</td>
<td>1,698.5</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Figure 15 - Bitumen Deposits with No Recovery Factor

- Carbonates: 48%
- Too thin: 44%
- Insufficient cap rock: 4%
- Intermediate depth: 3%
- Low pressure gas cap: 1%

Data source: (Alberta Energy and Utilities Board 2005)
**Bitumen Deposits Accessible with Commercial Recovery Technologies**

**Deposits Recoverable by SAGD, CSS or Equivalent Thermal Technology**

The largest category of deposits that are recoverable with current commercial technologies is the category associated with thermal technologies such as SAGD and CSS. In situ recovery is used for bitumen deposits buried too deeply for mining to be practical. Innovative technologies such as CSS and SAGD were developed to allow commercial exploitation of buried deposits. Novel technologies are emerging such as Vapour Recovery Extraction (VAPEX) and Toe to Heel Air Injection (THAI). In aggregate, this category is generally composed of thick, rich channel sands and represents 83.5 billion m$^3$ or 31% of the total oil sand resource.

SAGD is considered a “gentle” recovery process because it uses lower steam pressures than CSS. It is also robust with respect to thief zones because steam pressure can be used to balance pressures and avoid influx of water. Environmental concerns are also less with SAGD.

Two major factors are considered to be limiting the deployment of SAGD: deposit thickness and depth.

**Deposit Thickness**

In Athabasca, the oil sand deposits are thicker in the central region, but thin out in areas surrounding the central thick channel oil sands. Thick bitumen deposits are more attractive for SAGD operators because they offer improved economics and lower environmental footprints. The key reasons are as follows:

- Thicker deposits contain more oil over the producing horizontal well.
- In SAGD, gravity is the drive mechanism. The maximum width of the steam chamber is determined by its maximum height because a minimum gravity gradient must be maintained. Thicker deposits result in a wider steam chamber and therefore increased well spacings. This reduces capital costs and the environmental footprint on the surface.
- Thicker deposits will lose less heat to the over and under burden.

For the purpose of this study, it was considered that 10 m should be the minimum thickness for SAGD even though commercial projects have been justified based on thicknesses of at least 25 m. Two reasons support this conservative approach:

- SAGD is a relatively new technology. Continuous technology improvements should allow SAGD to be economic at thicknesses lower than today's limit.
- Secondly, once thick deposits are exploited, SAGD operators may find it economic to continue using surface facilities already built to produce steam and to handle produced liquids. Using the same surface infrastructure for the
surrounding thinner deposits would avoid significant costs and could make recovery of thinner deposits economic.

Deposit Depth

SAGD is more attractive at greater depths because greater overburden thicknesses enable the process to operate at higher steam pressures and temperatures. More aggressive steam conditions increase bitumen production rates. Higher steam temperatures create more reduction in bitumen viscosity and therefore result in higher bitumen production rates than at lower steam temperatures. However, steam at lower temperatures is more efficient because it contains a greater portion of usable heat and because the reduced thermal gradient results in less losses to the over and under burden. The net effect, however, is a higher total cost. An associated issue is the need for artificial lift in low pressure SAGD operations.

The minimum depth for SAGD is currently subject to technical investigations. Low pressure SAGD is currently being piloted with steam alone or with added solvent mixtures in order to extend the range of deposits accessible to the process. A number of projects approved under the IETP target improvements in low pressure SAGD.

Surface Mineable Oil Sands

Oil sands development initially started in Athabasca using surface mining. Mineable bitumen deposits are located near the surface and can be recovered by open-pit mining techniques. While the surface mineable area of Athabasca holds a gross amount of approximately 10% of the oil sands resource, the quantity that is actually economically recoverable by surface mining is only 9.4 billion m³ or 3.5% of the total resource.

About two tonnes of oil sands must be dug up, moved and processed to produce one barrel of oil. Technology developments over the past decades have been instrumental in making oil sands recovery economic and enabling the current scale of commercial development. For example, the oil sands operations of Syncrude, Suncor and Shell near Fort McMurray use the world's largest trucks and shovels to economically recover bitumen.

The depth to which surface mining is economic depends on several factors, in particular the economic strip ratio which is defined as the ratio of overburden material to recoverable ore. A rule of thumb is a one-to-one ratio of overburden to deposit thickness at an oil mass percent of 11%. In reality, they are seven to eight factors that need to be considered in order to determine the economics of oil sands recovery by surface mining.

It is currently economic to mine to a depth of 40-50 meters. This would be three benches of approximately 15 m each. For exceptionally rich deposits it is possible to add another bench or another 15 to 20 m but this would be exceptional.

For the purpose of this study however, surface mining was deemed to be economic to a depth of 40m on a deposit wide basis, thereby matching the approach adopted by the EUB.
Most of the area amenable to surface mining has been leased and, within the next five years, technology and infrastructure will be in place to recover most surface mineable oil sands. It may be already too late to conduct basic R&D for surface accessible deposits.

In surface mining, the opportunity could be to support pilots for adoption of new technologies as opposed to supporting basic research. The purpose would be to reduce environmental impacts such as tailings ponds and to reduce costs. Reducing the cost of surface mining would open up a significant amount of bitumen resources to recovery by surface mining.

Beyond increasing the depth economically accessible from the surface, programs to improve the reach of surface mining could also target low quality ores and small fragmented deposits that are not being recovered presently.

The deposits that were chosen for the first oil sand mines were those where the deposits were thick, rich and laterally continuous over a wide area. These factors favoured the economics of the project. As the industry expands, deposits with different characteristics are now being developed. An example is a recent surface mining project where one of the features is that, in some areas of the lease, deposits are fragmented into small surface deposits. This characteristic is a challenge for the operator and may require the use of innovative approaches.

The EUB estimates the size of small fragmented surface mineable oil sands at 10% of the surface mineable volume. Therefore small fragmented surface deposits represent approximately 900 million m$^3$ or 0.3% of the total oil sands resource.

Surface mining with present technologies requires that areas be set aside for tailings ponds. The area currently covered by tailing ponds is estimated at 20,000 hectares. This area is bound to increase substantially as new mines are constructed.

While efforts are made to locate tailings ponds over poor quality oil sands, this is not always possible. The EUB estimates the size of surface mineable oil sands sterilized by all surface facilities, including tailings ponds at 10% of the surface mineable volume. Therefore, less than 900 million m$^3$ or 0.3% of the total oil sands resource would be under tailings ponds. As indicated above only a fraction of this volume would be considered attractive deposits.

Prior studies have indicated that it could be technically possible to extract oil from deposits under tailings ponds. There is enough of a water column for SAGD at the depths of deposits under tailings ponds. What would be required is the quantification of how much oil is present under each tailings pond and related detailed engineering studies.

One motivation for R&D with respect to surface mining could be future scarcity of water and the related issue of the future of tailings ponds. The technical challenge presented by tailings ponds is underscored by the facts that the tailings are composed of 30% clay, and the ponds themselves are 40 m deep with a 4 m mud line.

**Deposits Capable of Cold Primary Production**

Bitumen viscosity is not uniform across the Alberta oil sands. In some deposits, bitumen viscosity is low enough to allow cold primary production. The downside of cold primary
production is that the recovery factor is low, in the order of 5% for bitumen to 15% for conventional heavy oil.

This production method can involve vertical or horizontal wells. In conventional heavy oil production with sand (CHOPS), sand is produced with the oil. The result is increased production and a higher recovery factor. CHOPS is primarily used in the Lloydminster conventional heavy oil area. However, sand production weakens the structural integrity of the reservoir and may cause breakdown of the roof which could then cause water to enter into the reservoir. At that point, recovery is no longer economic.

While in some oil sands areas bitumen viscosity is low enough to allow cold primary production, the viscosity is still too high for CHOPS. Most of cold primary production of bitumen is done without sand production. As a result, the recovery factor is lower.

The majority of cold bitumen production is from the Cold Lake area which is the region north of Lloydminster. In Athasbasca, cold production is found in the Wabasca area, where water floods are being piloted in an effort to increase recovery factors. In Peace River, cold primary production is found in the Seal area.

Although a relatively low bitumen viscosity allows early recovery with cold production, the downside is clearly the low recovery factor. It is also possible that, once a reservoir has been produced by cold production, the reservoir is no longer suitable for other technologies, particularly those that rely on the injection of steam or solvent. Cold production may cause early water ingress and CHOPS leaves behind a network of wormholes. These conditions are challenges for communication and containment of injected fluids.

New technologies with higher total recovery factors could be developed to replace existing methods of cold production. Another path could be to develop recovery technologies that would be applied as follow-up techniques after the potential for primary exploitation has been exhausted.

**Bitumen Deposits with No Recovery Factor**

**Bitumen in Carbonate Formations**

As discussed earlier in this report, over one quarter of Alberta's bitumen resources are not contained in sand formations but in carbonate formations. As shown on Table 14, there are four bitumen bearing carbonate formations in Alberta, two in Athabasca (Grosmont and Nisku) and two in Peace River (Shunda and Debolt). There is presently no commercial method to recover bitumen from Alberta carbonate formations and the recovery factor for these deposits is zero.

Bitumen is contained in a dual porosity system. Bitumen is held in the carbonate matrix. However, bitumen also occurs in natural fractures called “vugs” with diameters of up to 10 cm and larger. An important challenge is that the formation is highly variable over short distances because of the complexity of the natural fracture system.
Table 14 – Bitumen in Carbonate Formations

<table>
<thead>
<tr>
<th>Region</th>
<th>Deposit</th>
<th>Volume In Place (billion m³)</th>
<th>Percent Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Athabasca</td>
<td>Grosmont</td>
<td>50.5</td>
<td>71.0%</td>
</tr>
<tr>
<td></td>
<td>Nisku</td>
<td>10.3</td>
<td>14.5%</td>
</tr>
<tr>
<td>Peace River</td>
<td>Debolt</td>
<td>7.8</td>
<td>11.0%</td>
</tr>
<tr>
<td></td>
<td>Shunda</td>
<td>2.5</td>
<td>3.5%</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>71.1</td>
<td>100%</td>
</tr>
</tbody>
</table>

The most significant deposit is the Grosmont platform in Athabasca. Figure 16 illustrates the location of the Grosmont in relation to oil sands deposits. The Grosmont platform is 500 km in length and 150 km in width and buried at depths ranging from 250 m to 420 m. Its total thickness is approximately 170 to 180 meters. Pay thickness varies considerably from 25 m to over 80 m. Bitumen saturation is high. Bitumen accumulation is highest on the eastern margin. However, the bitumen is heavier than Athabasca in oil sands with API gravity of 5° to 9°.

The Grosmont formation is a carbonate shelf deposit that sub crops at the Pre-Cretaceous unconformity. Bitumen and gas are trapped along the Grosmont subcrop edge with Cretaceous shales as cap rock. The Grosmont formation is composed of four units separated by shale beds. They are listed below, from top to bottom (Walker 1986; Yoon 1986):

- **Upper Grosmont 3**: Thick and rich in bitumen accumulation; less attractive reservoir because of overlying gas pools and thief zones; natural gas is sometimes found at the top of the Grosmont unit 3 in the pre-Cretaceous unconformity area;
- **Upper Grosmont 2**: Relatively thick laterally extensive pay; has been the primary target for production pilots in the 1980s;
- **Upper Grosmont 1**: Relatively lower porosity and bitumen saturation and thinner pay zones;
- **Lower Grosmont**: least attractive zone.

The Grosmont was the object of three recovery pilots in the 1980s: Buffalo Creek, McLean and Chevron Algar. However results were described as spectacular but erratic and the production pilots were abandoned. Information about these pilots, as obtained
Buffalo Creek Pilot (Union Oil, Canadian Superior and AOSTRA)

In 1976, the Union Oil Company of Canada filed an application with the Energy Resources Conservation Board (ERCB) for an experimental heavy oil recovery scheme involving the Grosmont formation in the Buffalo Creek area of west Athabasca. The location was Township 88, range 19 W4. The target formation was the Grosmont unit 2. The purpose of the pilot was to investigate communicative heating approaches to bitumen recovery. It also aimed at evaluating potential problems with high permeability thief zones. Finally, the pilot sought to evaluate the potential of natural gas from the Grosmont unit 3 which overlies unit 2. In 1979, AOSTRA joined Union Oil and its
partner Canadian Superior in funding the Buffalo Creek and the subsequent McLean pilots.

The scheme was to inject water at 80% quality steam and to observe steam movement through observation wells drilled 30 m on either side of the injection well. Radioactive tracers in steam were used to monitor preferential channels in the formation. After steam injection the injection well was to be produced. The next phase of testing would have been a steam drive and/or a wet combustion test.

Access to the site is through a 140 km winter road from Wabasca. The absence of permanent access to the site meant that fuel and other supplies could only be trucked in the winter. During winter months, winter roads allowed trucking of bitumen to market. However during other times of the year, bitumen was re-injected into the Grosmont formation. Other produced fluids from the test were also injected back into the Grosmont formation using disposal facilities.

The well penetrated 120 m of the Grosmont formation at depths between 380 m and 260 m. The net pay was estimated at approximately 30 m. The well was cored and permeability was found to be greater than 10 md and the average porosity was measured at 16.7%. However porosities greater than 40% were obtained from 4 measurements. Oil saturation average nearly 80% oil. The oil contained 3 to 5% sulphur. Oil in place was estimated at 1,300 barrels per acre foot. No gas was expected from the Grosmont unit 2. Solution gas from the bitumen was expected to be negligible.

High production rates of 440 barrels per day were achieved.

In 1981 the well was in its fifth cycle. The company said that each cycle had provided unique and encouraging results. The termination criteria of two consecutive cycles indicating a deteriorating trend had not yet occurred by 1981.

By 1984, the well had completed its ninth steam stimulation cycle and was still producing. A second well was in its second cycle. In 1985, Union Oil applied to drill yet another well to further investigate production and communication issues. The pilot was terminated in 1986.

**McLean Pilot (Union Oil, Canadian Superior and AOSTRA)**

In 1982, Union Oil applied to the ERCB for approval of an experimental heavy oil recovery scheme in the McLean area, targeting the Grosmont formation. The location was 27-87-19W4, near the Buffalo Creek pilot. The objective was to obtain reservoir performance information for the Grosmont unit 2 by cyclic steam stimulation in a multi-well pattern. The project was to determine pertinent information such as well spacing, slug size, timing of interference, calendar-day oil rate and steam oil ratio.

The zone of interest was the Grosmont unit 2. It is a fairly uniformly thick unit. The porosity is fairly continuous within this unit. It is bitumen saturated throughout the zone. Unit 2 is bounded by shales 1 to 3 m thick. The shales are believed to be major barriers to vertical fluid and gas transmissibility. The top of the structure is 254 m above sea level while the bottom is 219 m above sea level.

The Grosmont unit 3 formation lies above unit 2 and is about 29 m thick. The Grosmont unit 1 formation lies below unit 2 and is roughly 16 m thick. All of these formations are
hydrocarbon bearing. The Lower Grosmont unit is 45 m thick. These units are separated by shales which are permeability barriers between the units.

In the vicinity of the pilot, the Grosmont units are relatively laterally continuous except where channelling eroded down into the Upper Grosmont. There was no gas found in the Grosmont unit 2. Any gas in place may only be minor quantities in solution.

<table>
<thead>
<tr>
<th>Table 15 – Reservoir Parameters for Carbonate Production Pilots</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buffalo Creek</td>
</tr>
<tr>
<td>----------------</td>
</tr>
<tr>
<td>Average Formation Depth (m)</td>
</tr>
<tr>
<td>Formation Temperature (°C)</td>
</tr>
<tr>
<td>Initial Reservoir Pressure (psig)</td>
</tr>
<tr>
<td>Bitumen Zone Gross Pay (m)</td>
</tr>
<tr>
<td>Net Pay (m)</td>
</tr>
<tr>
<td>Porosity (%)</td>
</tr>
<tr>
<td>Bitumen Saturation (%)</td>
</tr>
<tr>
<td>Pore Oil (%)</td>
</tr>
<tr>
<td>Water Saturation (%)</td>
</tr>
<tr>
<td>Pore Water (%)</td>
</tr>
<tr>
<td>Gas Saturation (%)</td>
</tr>
</tbody>
</table>


First steam injection was planned for July 1982. The steam drive would proceed from a central injection well. Succeeding cycles would continue until production data would be no longer useful. At that point, a steam drive test would be considered.

Loss of steam containment occurred because tunnels or vugs established communication between the Grosmont units 2 and 3. There was also premature steam breakthrough from injection to producing wells. The outcome was conflicting results.

In 1985, only one well was still active in the McLean pilot. Union Oil filed an amendment to its original application to drill an additional well. The purpose was to continue to investigate recovery of bitumen from the Upper Grosmont, to establish single
well parameters for cyclic steam stimulation and to establish reservoir performance and productivity parameters for the formation. The pilot would continue to use cyclic steam stimulation. Another objective was to investigate Grosmont unit 3 productivity and investigate communication between the units. However, the pilot was terminated in 1986.

**Chevron Algar Pilot**

In 1975, Chevron Standard Limited applied to the ERCB for a steam stimulation pilot in the Algar area, location Township 81 range 17W4. Chevron was planning to steam stimulate the unit 3 of the Grosmont carbonate formation for the production of bitumen in single well scheme. The objective of the pilot was to determine if steam stimulation of the Grosmont carbonate formation would be feasible for the recovery of bitumen. The operation was conducted in the winter of 1976 until spring break up. The company expected that there would be sufficient time for one or two steam cycles depending on the results of the first cycle. One to two weeks would be required to inject steam, two days for soaking, and three to four weeks for producing. Access to the site was only through a winter road.

In the Algar area, the sands of the McMurray formation are poorly developed. The Grosmont is underlain by shale deposits. In the project area, the Grosmont was anticipated to be 100 m in thickness and unit 3 was anticipated to be 25 m thick. The pilot well was to be terminated about 18 m into unit 3. The average depth to unit 3 was about 300 m. The average pressure and temperature were estimated at 200 psig and 24°C. Production was estimated at 250 barrels of fluid per day, composed of 50 barrels of bitumen and 200 barrels of water per day. The bitumen produced was incinerated on the site.

**Current Situation in Athabasca**

Husky Energy now holds oil sands leases in the same townships as the Union Oil pilots of the 1980s and is developing its Saleski project which is targeted at the Grosmont formation. In February 2006, land sales attracted record pricing for oil sands leases. Royal Dutch Shell has since come forward as being the anonymous buyer who acquired a package of oil sand leases for $465 million. These new leases are 100 km west of Fort McMurray, in the area of the eastern edge of the Grosmont carbonate platform. It appears that major oil companies have now taken notice of the potential offered by bitumen in carbonates.

**Peace River Carbonates**

In 1985 Pembina Resources applied to see ERCB to drill a single well thermal in situ experimental scheme in the Seal/Chipmunk area of Peace River. The location was Township 82, Range 12W5. The target was a carbonate zone in the Pekisko formation. The reservoir is described as not a reef but a Pekisko carbonate mud mound build up otherwise known as “Waulsortian Mound”. Underneath the Pekisko formation are Banff shales. Overlying the carbonate zone are 32 m of Pekisko shales. Overlying the shales is the Shunda carbonate formation with inter-bedded shales for 100 m. Shunda carbonate formation contains bitumen and heavy oil but Pembina believed its porosity to be too low for commercial exploitation.
According to the application, the experimental scheme was to be carried out during the winter of 1985-86. It was a single well steam stimulation pilot. Steam was to be injected for 20 to 25 days above fracture pressure. After steam injection, a soak period of one to two weeks was allowed. Then, the well was to be produced until liquids become too cool for production. Produced liquids, water and bitumen, were to be trucked away for treatment. Production was expected to last four months or longer.

Today, in the same general location BlackRock Ventures is developing its Chipmunk project which also targets the Pekisko carbonate formation. Three vertical wells are now producing 960 bpd of 11° API oil using cold primary production without steam. For the Chipmunk project, BlackRock is partnering with Talisman Energy. In 2006, an expanded 3D seismic and delineation program costing approximately $10 million is planned for Chipmunk.

**Research and Development Needs**

The complexity of carbonate geology needs to be recognized. The first step would be to obtain geological and geophysical data to characterize the formations accurately, such as:

- Understanding rock geology using 3-D seismic
- Data on permeability and porosity
- Mapping of vugs and fractures
- Identification of gas zones above or below the oil bearing formations
- Mapping of water zones and hydrology.

Bitumen characterization is also required with respect to its physical but also to its chemical properties. Chemical interactions of bitumen and carbonates with steam, CO₂, water and other injectants need to be understood. There is a need to investigate if steam would cause formation damage to the carbonates matrix because of thermal and water related effects. In addition, when accessing carbonate formations, there may be a need to control the pH of the steam because acidic waters may cause formation damage. Similarly, injecting CO₂ in carbonate formations may also cause damage to the carbonate structure. These effects need to be understood. Therefore there is a need at an early stage to develop a deep understanding of physical and chemical properties of carbonate formations in Alberta and their reactions to different fluids that may be injected.

There might also be particulate matter and sediments that would be mobilized with the oil and that could plug channels and vugs.

The Grosmont formation is difficult to develop because it exhibits close to complete saturation of low viscosity bitumen. The natural fractures add considerable difficulties for drilling, completions and steam containment. The challenges faced by the earlier pilots include:

- Drill bit dropped few meters when passing through large vugs
- The irregular network of vugs can lead to a loss of mud circulation while drilling
- Difficult placement of cement for well to formation bond
- High bitumen viscosity
- Low effective permeability
- High reservoir heterogeneity
- Dual porosity system
- Difficult drilling and completion
- Poor containment of injected fluids
- Isolated area with poor road access
- Designated caribou migration area

However, the problems encountered 20 years ago during trials in the carbonate formations could be solvable today. The industry now has drilling technologies such as horizontal wells and well completion technologies that would increase the likelihood of successful recovery of bitumen from carbonates.

The challenges facing the development of bitumen in carbonates in Alberta are similar to those faced when developing carbonate formations in other international settings. It would be valuable to stay informed of what is done on a worldwide basis to recover oil from vugular carbonate formations.

**Thin Oil Sands**

As discussed earlier, thin oil sand deposits are found everywhere as they surround the central thick channel oil sands. Thin oil sands are a considerable resource. For the purpose of this study, deposits thinner than 10 m are considered not recoverable with current commercial technologies and have been assigned a recovery factor of zero. Using this cutoff, thin oil sands represent a volume in place of 65 billion m³ and account for one quarter of the total Alberta bitumen resource. Over 90% of thin oil sands are located in the Athabasca region.

If a larger thickness had been chosen as the cutoff (for example 25 m as for current commercial projects), then the volume of thin oil sands identified would have been significantly larger.

Thin bitumen deposits are less attractive for SAGD operators because they offer reduced economics and increased environmental footprints. The key factors are as follows:

- Thinner deposits contain less oil over the producing horizontal well.
- In SAGD, a gravity drive must be maintained. This dictates the maximum width of the steam chamber as a multiple of its maximum height. Thinner deposits result in a narrower steam chamber and therefore reduced well spacings. This increases capital costs and the environmental footprint on the surface.
- Thinner deposits will lose more heat to the over and under burden.

A related issue is the possible presence of shale or clay layers inside an oil sands deposit. A thick shale layer will effectively convert the deposit into two thinner deposits. SAGD
is a gentle process and is not capable of breaking thick shale deposits in the same manner as the more aggressive CSS process. The thickness of shale layers that would be sufficient to stop the vertical expansion of a SAGD steam chamber is still the subject of investigation. A view often presented, and supported by data from the UTF, is that thick shale or clay zones are not likely to be laterally continuous and would act more as a baffle than as a barrier. Therefore, thick shales or clays would have the effect of altering the shape of the steam chamber and possibly reducing the final recovery factor.

Thin shales, on the other hand, even if laterally continuous, would be broken down, in time, by SAGD. When steam hits a shale inter-bed or a clay layer the water swells the clay and breaks the layer thereby removing the barrier. The net effect could be a reduced production rate and a poorer cumulative steam to oil ratio. There is also a view that the presence of thin shale zones would aid the development of the SAGD steam chamber. In clean sands, the steam chamber does not develop properly and grows in height too fast. The presence of a thin shale inter-layer delays the vertical growth of the chamber and allows it to develop horizontally.

There are few, if any, known R&D programs and industry development aimed at developing thin oil sands. Thick oil sands are abundant and more rewarding. As a result, they are receiving all of the attention. Low pressure SAGD, which is discussed in the next section, would offer the benefit of less heat losses to the over and under burden. Low-pressure SAGD could allow the recovery of thin reservoirs because low-temperature steam results in less heat losses to the over and under burden. The temperature of steam in low-pressure SAGD is 180° C as compared to 250° C in regular SAGD.

Solvent processes, such as VAPEX, do not use heat and heat losses are not a concern. However, VAPEX is a gravity process and would perform better in thick reservoirs. Finally, in situ combustion processes, when perfected and controlled, could offer a solution for thin oil sands because heat losses are not a major concern and they do not rely on gravity.

**Deposits Too Deep for Surface Mining but Too Shallow for SAGD**

Intermediate zone oil sands are deposits that are too deep for surface mining but too shallow for SAGD. For the purpose of this study, intermediate zone oil sands are defined as oil sands at depths from 40 to 75 m. They represent a resource of 4.4 billion m³ or 1.6% of the total oil sand resource. However, as discussed earlier, depth is a crude approximation of the economic limit of surface mining. The minimum depth required for SAGD is currently subject to technical investigations. Low pressure SAGD is presently being piloted with steam alone or with added solvent mixtures in order to extend the applicability of the process.

A reasonable expectation, one that is shared by the EUB, is that, over time, technology advances in surface mining and in SAGD will eliminate the zone that is currently inaccessible because it is too deep for surface mining and too shallow for SAGD. In fact, at least two commercial projects, Jocelyn and Horizon, are planning a surface mine and an in situ development on the same lease. In addition, SAGD projects are being located on leases that are immediately adjacent to existing surface mines. It is therefore reasonable to expect that incremental advances in technology and increased collaboration
between neighbouring operations will eventually succeed in recovering bitumen from the intermediate zone.

**Low Pressure SAGD**

The minimum depth for SAGD is also subject to several factors. At first approximation, a shallower depth implies a shorter water column and therefore lower steam pressures and temperatures must be used. In reality, depth is less of an issue if there is an effective seal layer that can contain steam. There are also many reservoirs which are at lower pressure than expected given their depths. An example of an under pressurized reservoir is Firebag. It is at a pressure of 800 kPa versus an expected pressure of 3000 kPa.

Lower steam temperatures cause production rates to be reduced because bitumen viscosity is higher at lower temperatures. However the steam to oil ratio is improved because lower pressure steam contains a higher percentage of latent heat. Low-pressure SAGD results in lower production rates but it is more energy and water efficient and requires less natural gas. The net effect, however, is a higher total cost because of the lower production rates (Good, Rezk et al. 1997). Because of the lower temperatures, low-pressure SAGD also reduces the amount of CO2 and hydrogen sulphide that is directly related to the production of bitumen from thermal processes.

An associated issue is the need for artificial lift in low pressure SAGD operations. Electrical submersible pumps and other lift technologies such as high volume lift systems are now being evaluated for this purpose. New pump designs may need to be developed.

ES-SAGD is also a new technology that is being applied to shallow oil sands. In this technology, a diluent is added with the steam. The diluent is carefully selected to condense at the same conditions as steam.

It is also more difficult to drill horizontal wells for shallow depths. At shallow depths, one of the challenges is to avoid fracturing the reservoir when drilling.

**Deposits with Insufficient Cap Rock, Shale or Clay Barrier**

Current commercial thermal in situ technologies, such as SAGD and CSS, inject steam into the deposit. This steam needs to be contained inside the deposit for the process to work and to be economic. Some deposits, mostly in Athabasca, lack sufficient overlying rock, shale or clay barrier for effective containment of steam. These deposits are located mostly in the northeast quadrant of Athabasca where glacial erosion has removed the shale or clay barriers between the oil sands and overlying sediments.

Throughout much of this area of bitumen exists at depth greater than 50 m but the recovery factor is assigned as zero because standard thermal in situ method would not be capable to operate in this situation. In aggregate, deposits with insufficient cap rock account for 5.8 billion m3 or 2.1% of the total bitumen resource.

Recovery technologies that do not involve steam, such as VAPEX and in situ combustion may be applicable for deposits lacking containment.
Deposits in Communication with Low Pressure Gas Caps

The presence of shallow gas reservoirs overlaying bitumen deposits has received considerable attention from the industry and the EUB. The issue is that the bitumen zone is in communication with the gas zone and, therefore, steam injected into the bitumen zone could escape into the gas zone. In effect, the gas zone becomes a thief zone that may severely reduce the effectiveness of the thermal process.

In cases where gas reservoirs are currently at a sufficient pressure to avoid the escape of steam from the bitumen zone, the EUB has ruled that these gas reservoirs cannot be produced in order to maintain their pressure and to protect the ability to recover the bitumen by using SAGD type technologies. These bitumen deposits are deemed recoverable because the gas zones are shut-in under a conservation order.

However, there are gas reservoirs overlying bitumen deposits that are currently at a pressure too low for containment of steam. These reservoirs were either naturally at a low-pressure or have already been produced. There is no current commercial technology that can recover bitumen from deposits in communication with low-pressure gas zones. As a result, these bitumen deposits have a recovery factor of zero. They are mainly located in Athabasca and account for 2.2 billion m³ of bitumen or 0.8% of the total bitumen resources.

It should be noted that a number of projects approved under the IETP are targeting technology solutions for this issue. Air depleted of oxygen could be used as the gas for pressurization or re-pressurization of low-pressure gas pools. One major oil company is reported to have re-pressurized two pools using this technique.

Another option could be to re-pressurize using produced gas. This is natural gas that is not good enough to sell but that could be stored in a shallow gas pool and used later for local combustion applications.

Nitrogen injection is also a possibility. There is a very large nitrogen injection project in Mexico for conventional oil production.

Another direction involves operating low-pressure recovery processes such as SAGD and VAPEX.

Shallow gas reservoirs may actually be recharged naturally over time by water influx. However it is not known if it indeed happens and how fast. Natural recharge could be an important area of investigation because it could lead to technologies for re-pressurizing depleted gas caps.

Top or bottom water zones

Water zones are also thief zones for injected steam. However, it is considered that these situations do not completely prevent the use of commercial technologies such as SAGD and CSS. The presence of thief zones will however reduce the recovery factor and negatively impact the economics of the project. The extent of such an impact will depend on the particulars of specific deposits. Overlying water zone reduce bitumen recovery and increase the steam to oil ratio and overall costs. Reservoir mechanisms of steam moving into water sands are very complex and not completely understood.
It may also be possible to use water zones to enhance recovery. An example is some of Shell’s trials in Peace River where a bottom water zone was used to distribute steam throughout the deposit. Steam was injected in the bottom water zone and rose into the overlying bitumen, thereby softening the bitumen and allowing production.
TECHNICAL CHALLENGES

The current commercial technologies, while economic for the recovery of bitumen, are faced with significant technical challenges. These challenges only will be described briefly in this the report because they have been covered extensively in prior works (Alberta Chamber of Resources 2004; Heidrick, Bilodeau et al. 2004; Flint 2005; Peachey 2005).

Surface mining and thermal in situ technologies are energy and water intensive. A consequence of energy intensity is greenhouse gas emissions. The industry is in need of new technologies that would use less natural gas and less fresh water in order to be sustainable and cost competitive in the future.

Natural Gas Consumption

The development of oil sands is currently an energy intensive undertaking. As discussed in the Oil Sands Technology Roadmap (OSTR), surface mining requires 250 cubic feet per barrel for extraction and 500 cubic feet per barrel of synthetic crude for upgrading. In-situ technologies such as CSS and SAGD consume 1,000 cubic feet of natural gas per barrel of bitumen recovered and an additional 500 cubic feet per barrel for upgrading. These levels of natural gas consumption mean that:

- Surface mining and upgrading consume approximately 12% of the energy content of the produced SCO
- Thermal in situ technologies and upgrading consume approximately 24% of the energy content of the produced SCO.

In 2004 oil sand production required an estimated 0.7 bcf per day of natural gas. Forecasted industry growth to 3 million barrels per day (bpd) of bitumen production would entail, using existing technology, a consumption of over 2.5 bcf per day of natural gas. A production level of 5 bpd, as envisioned by the OSTR, could consume an unthinkable 60% of Alberta natural gas supply by 2030, unless new technologies or alternative sources of fuel are developed and used.

One of the environmental impacts of energy intensity is greenhouse gas intensity. According to the Canadian Association of Petroleum Producers (CAPP), greenhouse gas emissions associated with petroleum production are as follows:

- 0.23 tonnes CO₂ per m³ for conventional oil
- 0.46 tonnes CO₂ per m³ for in situ bitumen
- 0.52 tonnes CO₂ per m³ for bitumen mined and upgraded to SCO.

Fresh Water Consumption

Fresh surface water and groundwater are limited resources in Alberta. In the oil sands area most of industry needs for makeup water are provided by the Athabasca River.
While adequate supply is available, eventually, the river will reach its limits, particularly during the low flow periods of the winter months. Technologies that use less water or use recycled or brackish water would reduce the need for fresh water makeup.

In 2004 approximately 2.4 million barrels of water per day were consumed in oil sands production. Industry growth to a production level of 3 million bpd could increase water consumption to over 5 million barrels per day.

**Diluent Usage**

Bitumen is too viscous for transportation by pipeline. It must be diluted with either diluent or synthetic crude. In 2004 diluent usage for oil sands was just less than 100,000 barrels per day. Diluent requirements could increase to more than 250,000 barrels per day by 2020. Diluent availability is related to natural gas production and is currently expected to peak at around 200,000 bpd by 2006 and then decline in tandem with natural gas production.
New technologies will be required to improve production of bitumen and heavy oil, whether it is to increase the extent of recovery, to increase the rate of recovery, to lower costs, to address issues related to natural gas, water and diluent or to minimize environmental footprint. The future of oil production in Alberta lies with improved bitumen recovery. This can be accomplished by incremental improvements to existing methods, or, developing new and novel ones. Oil sands research and development is an important vehicle for the emergence of the innovative technologies that will be necessary to economically recover Alberta’s vast remaining bitumen resource.

Research and development were clearly instrumental in making oil sands the significant economic reality it is today. R&D and technology development must again be called into service to face the challenges and the opportunities that have been described in this report.

The first step is to take stock of current oil sands R&D activities. Two years ago, Alberta Energy commissioned a study of publicly funded oil sands R&D. This section provides a summary of the major findings of this work.

**Methodology**

Information about the extent and intent of oil sands research was obtained from funding organizations as well as providers of research services. In most cases, this information was available on a project by a project basis for the five years covered by this inventory. Each project was reviewed and characterized according to categories and parameters designed to aggregate the information in a manner supportive of strategy and policy development.

While the focus of the study was oil sands, heavy oil was also included in the survey because technology developed for heavy oil can, and is, also applied to bitumen. For example, the VAPEX recovery technology is currently undergoing demonstration trials in bitumen reservoirs as well as in heavy oil reservoirs. SAGD technology is an initial recovery technology for bitumen, but could also be considered for use as a follow-up method in heavy oil reservoirs exploited with cold primary production.

R&D projects were assigned to the following categories:

- Research stage
- Stage of resource development
- Improvement opportunity
Stage of R&D

R&D spans the range from fundamental research aimed at knowledge creation to market research designed to establish current and future market needs. Applied research is intended to apply fundamental knowledge to specific technical challenges. Demonstration is the critical step where new technology is taken out of the laboratory and evaluated under realistic field conditions. Commercialization includes the activities required for the first commercial facilities. Market research is concerned with obtaining market information regarding current and future products. No government funded market research projects were found by this study, possibly indicating a need for future work. With respect to the Research Stage category, projects in this inventory were assigned to one of the following stages:

- **Fundamental**: Fundamental research is aimed at creating new scientific knowledge and at understanding basic principles and relationships. Universities are major contributors to fundamental research.
- **Applied Research**: Applied research is concerned with the application of science to current and future challenges faced by society and industry. Industry and government laboratories such as ARC and NCUT conduct a significant amount of applied research.
- **Demonstration**: Science and engineering based solutions developed in the laboratory need to be demonstrated in the field under small scale conditions that replicate commercial operations as closely as possible. Demonstration is necessary before significant capital can be approved for commercial facilities.
- **Commercialization**: Commercialization activities involve studies, testing and evaluation required to establish competitive position (opposite competitive offerings), market position (with respect to market needs), environmental impact, safety and manufacturing reliability and costs.
- **Market Research**: The business plan supporting the approval of commercial facilities is generally based on targeted market studies aimed at forecasting prices, costs and profit in order to calculate the return on investment of future earnings, often using a range of scenarios. In general, universities and government laboratories do not conduct market research.

Stage of Resource Development

Research projects were also characterised by the resource development stage that was targeted. Oil sand deposits are first exploited by applying a certain initial technology to the recovery of oil from the reservoir. Depending on the technology used, the extent of recovery varies from 5% for cold primary production to as high as 90% for surface mining technologies. In cases where the initial recovery method yielded a relatively low rate of recovery, the opportunity exists to apply a second method as a follow-up technique to recover additional oil from the reservoir. The third step in the oil sands value chain involves upgrading bitumen into synthetic crude oil and transportation fuels. All along the value chain it is of paramount importance to consider environmental impact to air, water and soil. Of particular importance is the eventual remediation and
Reclamation of the land at the end of reserve life. Research projects were therefore classified as to which stage of resource development they applied to:

- Recovery
- Follow-up
- Upgrading
- Environmental – Air Quality
- Environmental – Water Quality
- Remediation and Reclamation

**Improvement Opportunity**

As described earlier in this report, the industry is facing significant challenges for the continued economic development of reservoirs for which recovery technology already exists. Concerns about use of natural gas, water and diluent may threaten the extent of oil sands development in the future. From the point of view of R&D, these challenges represent opportunities for improvements. R&D projects were therefore reviewed and assigned to one or more improvement category when they targeted such improvements:

- Reduced Energy Intensity
- Reduced Water Use
- Reduced Use of Diluent

**Summary of Publicly Funded R&D**

Total funding for bitumen and heavy oil R&D was approximately $117 million in the five years from fiscal 1998-99 to fiscal 2002-03. The funding organizations that provided the most funds were by a wide margin Natural Resources Canada (NRCan) ($46.7 million) and the Alberta Energy Research Institute (AERI) ($30.6 million). NRCan funding was almost exclusively directed to the operations of the laboratories and pilot plants located in Devon Alberta. AERI, by contrast funded a broad mix of targeted projects from fundamental research to commercialization performed by several facilities and sites.

Funding to universities was mostly through programs such as the Canada Foundation for Innovation, Canada Research Chairs, NSERC and programs administered by Alberta University Research and Strategic Investments. In aggregate, these funding agencies provided approximately $23 million over 5 years, primarily to universities. These funding programs support the infrastructure needs of universities as well as research chairs. These types of projects are often of a very broad scope and are useful to more than one industry.

Public funds provided for oil sands research were utilized by research organizations to conduct projects. The largest recipient ($38.9 million) was the National Center for Upgrading Technology (NCUT) in Devon, Alberta which is a federal-provincial partnership and received funds from NRCan, AERI, ARC, as well as other government sources. This facility is dedicated to research into the upgrading of bitumen and heavy
oil into synthetic crude oil and transportation fuels such as gasoline, diesel and jet fuel. The second largest investment was for the associated federal CANMET facility in Devon ($18.7 million). This facility is funded by NRCan and industry. It conducts research into advanced separation technologies related to petroleum. The University of Alberta, the Alberta Research Council and the University of Calgary each received approximately $12 million over five years for bitumen and heavy oil research.

The largest amount of funding was directed at applied research and reflects the substantial amount of work conducted by NCUT and ARC. The next largest category is fundamental research which is conducted mostly by universities. Demonstration trials attracted a relatively small level of public funding.

Projects concerned with bitumen and heavy oil initial recovery attracted the most funding. A relatively small amount was spent on recovery techniques to follow-up on initial recovery and to improve overall recovery. This relationship is reasonable given the fact that oil sands developments are at an early stage. Upgrading commanded the second most important level of funding. This is due in a large part to the research conducted at the National Center for Upgrading Technology. It is important to underscore that the lowest level of funding was directed at research conducted into environmental issues. The aggregate amount of funds spent on environmental research was slightly more than 10% of the total amount spent on oil sands research.

Approximately 43% of oil sands volume in place is suitable for recovery by current commercial technologies such as surface mining, SAGD and CSS. The other types of buried deposits can not be economically developed unless new technology is made available. Most of the public research appears to have been directed at improving the efficiency of existing or near commercial technologies designed for deposit that are presently the object of active development. A much lower level of funding was targeted at marginal deposits. Very little work appears to have been directed at thin deposits. No projects could be identified that targeted bitumen in carbonate formations.

The improvement opportunity that attracted the most research funding was “Reduced Energy Intensity”. This is not surprising given the importance of energy costs, particularly natural gas usage, in the development of oil sands.

**Benefits and Responsibilities of Ownership**

One of the reasons to use public funds for oil sands R&D is that natural resources belong to the Alberta crown. Energy companies that exploit the oil sands do this under leases granted by the government. As the owner of the resource, the government enjoys the benefit of ownership such as receiving royalties but it also incurs the responsibilities of an owner. One of these responsibilities is to ensure that the resource is exploited effectively in a matter that not only is respectful of the environment but also maximizes value for current and future residents.

The oil sands are sometimes referred to as technology oil because technology development has been instrumental in unlocking its value. A technology such as SAGD does not only make oil sands recovery economic, but it does it with a high degree of effectiveness given that recovery factors of up to 60% are expected for active projects.
The government of Alberta actively contributed to the development of SAGD in the 1980s and 1990s. The government invested in the development of SAGD and other oil sands technologies because, as the owner of the resource, the government had a clear vested interest in the introduction of effective and economic recovery technologies.

In this respect, oil sands and other natural resources are different than most sectors of economic activity. The government of Alberta owns the oil sands while it is not necessarily the owner of assets in sectors such as manufacturing, biotechnology, ICT, etc. While government investment in R&D is positive for economic development, in the oil sands it carries the additional benefits and obligation of ownership.

**Alberta Oil Sands Technology and Research Authority (AOSTRA)**

The Alberta Oil Sands Technology and Research Authority (AOSTRA) was established in 1974 by the Alberta government. Its original mandate was to conduct research and development for oil sands. However the mandate was amended in 1975 to include conventional heavy oil and was expanded again in 1979 to cover enhanced recovery of conventional crude oil.

On its inception, AOSTRA received funding of $100 million for the first five years from the Alberta Heritage Savings Trust Fund. At the time, AOSTRA was the largest single R&D program ever launched in Canada. Alberta government funding commitments were renewed by an additional $150 million for the five years between 1980 and 1985. At that time Alberta’s public investment in oil sands R&D was approximately $250 million.

AOSTRA operated for 20 years from 1975 to 1994. Annual expenditures are shown on Table 16 and graphed on Figure 17. Average annual expenditures from 1977 to 1993, (excluding start-up and close-out years) were $57.4 per year in 2004 dollars. Over the 20 years of operation, AOSTRA spent a total of $617.1 million. However when adjusting these amounts for inflation the total investment made by the Alberta government in oil sands R&D through AOSTRA amounted to $1.0 billion in $2004. AOSTRA was funded as follows:

- Alberta Heritage Savings Trust Fund: $418.6 million
- Alberta General Revenue Fund: $176.7 million
- Technology sales: $21.8 million
- Total expenditures: $617.1 million

Over its history AOSTRA partnered with industry to fund oil sands R&D and demonstration pilots. On average over 20 years of operations, funding for AOSTRA supported projects was provided 53% by industry and 47% by AOSTRA itself. In 1994, the $12.4 billion provided by AOSTRA were matched by $40.5 million for industry. This 3.2 to 1 ratio of industry funding to government funding was a record achieved by AOSTRA during its last year of operation.
### Table 16 - AOSTRA Yearly Expenditures

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<thead>
<tr>
<th>Year</th>
<th>million dollars of the day</th>
<th>million 2004 dollars</th>
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<tbody>
<tr>
<td>1976</td>
<td>$2.2</td>
<td>$6.35</td>
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<tr>
<td>1977</td>
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<tr>
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<td>1979</td>
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<tr>
<td>1980</td>
<td>$38.7</td>
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<tr>
<td>1981</td>
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<tr>
<td>1982</td>
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<tr>
<td>1983</td>
<td>$37.8</td>
<td>$63.12</td>
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<tr>
<td>1984</td>
<td>$37.7</td>
<td>$61.02</td>
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<tr>
<td>TOTAL</td>
<td>$617.1</td>
<td>$1,005</td>
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Sources: (Alberta Oil Sands Technology and Research Authority 1980; Alberta Oil Sands Technology and Research Authority 1981; Alberta Oil Sands Technology and Research Authority 1982; Alberta Oil Sands Technology and Research Authority 1983; Alberta Oil Sands Technology and Research Authority 1984; Alberta Oil Sands Technology and Research Authority 1985; Alberta Oil Sands Technology and Research Authority 1986; Alberta Oil Sands Technology and Research Authority 1987; Alberta Oil Sands Technology and Research Authority 1988; Alberta Oil Sands Technology and Research Authority 1989; Alberta Oil Sands Technology and Research Authority 1990; Alberta Oil Sands Technology and Research Authority 1991; Alberta Oil Sands Technology and Research Authority 1992; Alberta Oil Sands Technology and Research Authority 1993; Alberta Oil Sands Technology and Research Authority 1994)
AOSTRA was effective because its mission was very well defined: to help develop commercially viable technologies for each of the major oil sand deposits, Athabasca - McMurray, Wabasca, Peace River, and Cold Lake. Essentially the entire effort was devoted to this clear objective during the first rounds of funding and the first 5 to 8 years. AOSTRA worked closely with industry, seeking the best ideas from companies through Requests for Proposals (RFP).

Once this was underway, AOSTRA initiated university based programs to generate a more fundamental understanding of the oil sand components and their interaction. A third wave of activity looked for new concepts, not then part of the arsenal of the oil companies. Two examples are the Alberta Taciuk Processor (ATP) and horizontal wells drilled via the Underground Test Facility (UTF), which ultimately led to SAGD.

AOSTRA had a large number of technical accomplishments but it is remembered primarily for the initial development of the SAGD process which has resulted in the investment by industry of approximately $100 billion of new oil sands commercial operations. In 1994, AOSTRA was merged into the oil sands and research division of Alberta Energy.

In addition to its technical accomplishments, AOSTRA played a critical role in the development of highly qualified people required to conduct and commercialize oil sands
R&D. AOSTRA developed people who are now in government and industry, acting as decision makers and technology receptors for R&D developments.

In summary, public funding of oil sands R&D by the government of Alberta averaged $57 million per year for a 20 year period during the 1970s to the 1990s. This amount is more than double the annual average of $23 million per year that is currently contributed by the provincial and federal governments combined.
Methodology

The process involved collaborative work with ADOE and the Alberta Energy and Utilities Board (EUB). Published and unpublished information from the EUB was relied upon to outline opportunities and challenges presented by various oil sands deposits.

Information about technology challenges was developed from many different sources:

- Alberta Energy;
- Alberta Energy Research Institute;
- Interviews with participating industry partners;
- A concurrent project managed by the Petroleum Technology Alliance Canada (PTAC) on the topic on inaccessible bitumen deposits;
- A review of recent technology literature; in particular, the comprehensive Oil Sands Technology Roadmap (OSTR) recently completed by the Alberta Chamber of Resources (ACR) was an important foundation;
- Data from Statistics Canada;
- Data for Research InfoSource, a Canadian company that tracks corporate and public R&D in Canada;
- Recent relevant projects completed by the principal investigators; and,
- Review of a large number of public documents published by oil sands companies such as annual reports and filings to the EUB.

Confidential interviews were conducted with all of the industry partners, as well as some companies who were willing to provide information for this study. As noted above, specific information obtained from specific companies, while used in the analysis and in the calculation of estimates, is not reproduced in the report.

Information from Alberta Energy Royalties

Under the royalty regimes of the Alberta government, energy companies pay royalties on net revenue, in other words revenues less costs. Companies file information with Alberta Energy concerning their revenue and cost in order to substantiate the amount of their royalty payments. R&D expenditures are considered part of costs and are therefore an eligible cost in royalty calculations.

At the start of this work, it was thought that cost data submitted by companies to Alberta Energy could be mined on a confidential basis in order to extract information about corporate oil sands R&D expenditures. However, Alberta Energy only reviews the details of company submissions on an audit basis. Therefore, Alberta Energy does not keep and maintain data on specific cost items such as R&D expenditures. Data about corporate R&D expenditures are therefore not available from this source.
Over the years, Alberta Energy has conducted many audits. However the audit department does not remember noticing significant R&D projects claimed by companies as part of their costs. The order of magnitude of R&D projects noticed by Alberta Energy auditors are of the order of magnitude of $100,000 per year for projects such as resource delineation and seismic work, or $50,000 for R&D in obtaining scale-up factors from pilot scale to commercial operations. This level of expenditures is clearly at odds with publicly reported information that estimates corporate oil and gas R&D in the range of $100 million per year. It appears, however, that energy companies can choose to apply corporate costs such as R&D expenditures against any energy royalty calculation. Therefore, because current oil sands developments are incurring a significant amount of start-up costs, oil sands operations are not likely to result in significant outstanding royalty payments, if any. Therefore it would be to the benefit of energy companies to claim R&D expenditures again is outstanding royalties from natural gas or conventional oil operations. This could explain why such small amounts of R&D appear to be conducted and claimed for oil sands developments when one uses royalty calculation information as the basis for analysis.

In summary, the amount of R&D expenditures noticed by Alberta Energy auditors are very small compared to publicly reported numbers and also compared to number recently announced for Alberta Energy’s IETP program. Two reasons are proposed to explain this discrepancy:

- The process followed by Alberta Energy auditors is an audit process and, as a result, sees only a small sample of all submissions;
- Companies can elect to apply corporate costs such as R&D expenditures to other outstanding energy royalty payments. Given that oil sands are in a phase of development that involves extremely high level of capital investments, it would be to the benefit of energy companies to claim corporate costs such as R&D expenditures again royalties owed for more mature resources such as conventional oil and natural gas.

As a result, no data from energy royalty calculation was accessed or used in this work.

**Statistics Canada**

Statistics Canada analyzes and publishes information on research and development expenditures in Canada. Statistics Canada’s source of data for R&D expenditures by companies is the Scientific Research and Experimental Development (SR&ED) program which is a federal tax incentive program to encourage Canadian businesses to conduct R&D in Canada. The SR&ED program is the largest single source of federal government support for industrial research and development.

Table 17 presents information obtained from Statistics Canada for business R&D expenditures for oil and gas extraction, which includes oil sands recovery. The same information is represented graphically on Figure 18 along with the annual average nominal price of crude oil between the years 1994 and 2005. It can be observed that oil and gas R&D in Canada dipped between 1998 and 1999, in all probability because of low oil prices. However R&D expenditures have now recovered likely in response to
increases in the oil prices. Oil and gas R&D in Canada now stands at double the rate of the 1994-99.

**Table 17 - Business Enterprise R&D for Canadian Oil and Gas Extraction**

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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>R&amp;D</td>
<td>$111</td>
<td>$109</td>
<td>$105</td>
<td>$137</td>
<td>$103</td>
<td>$88</td>
<td>$129</td>
<td>$164</td>
<td>$182</td>
<td>$182</td>
<td>$205</td>
<td>$211</td>
</tr>
</tbody>
</table>

Source: Statistics Canada CANSIM Table 358-0024

**Figure 18 - Business Enterprise R&D for Canadian Oil and Gas Extraction**

Sources: Statistics Canada CANSIM Table 358-0024 and U.S. DOE

**Research InfoSource**

Research InfoSource is a consulting organization that specializes in providing data and intelligence for businesses with respect to research and development and higher education. The company publishes an annual report on Canada's top 100 corporate R&D
spenders. Research InfoSource obtains its information from public document published by companies and by individual submissions from interested companies. The Top 100 R&D Spenders lists for 1999 through to 2004 were reviewed. Eight oil and gas companies appear on this list and information about their corporate R&D expenditures is summarized on Table 18.

<table>
<thead>
<tr>
<th>($ million)</th>
<th>1999</th>
<th>2000</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>EnCana</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alberta Energy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Company and PanCanadian</td>
<td>$13.8</td>
<td>$78.9</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imperial Oil</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Syncrude</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Suncor Energy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shell Canada</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Petro-Canada</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>$131.8</td>
<td>$182.9</td>
<td>$234.3</td>
<td>$213.3</td>
<td>$213.0</td>
<td>$294.4</td>
</tr>
</tbody>
</table>

Source: (Research InfoSource 2005)

While the data reported by Statistics Canada and by Research InfoSource is obtained from different data sources and subject to different methodologies, there are important similarities in the patterns presented. The magnitude of oil and gas R&D spending is similar, between $100 and $300 million. Statistics Canada numbers are lower for the probable reason that they only cover extraction activities and not upgrading and refining. Unfortunately, Statistics Canada information for upgrading and refining is aggregated with coal processing. Both organizations also report a large increase in corporate R&D spending for oil and gas between 1999 and 2004.

It also appears that most oil and gas R&D is performed by a few large companies. Statistics Canada numbers are for the industry as a whole and yet they are of a comparable magnitude to the top companies. Oil & gas R&D requires the deployment of substantial laboratory, bench scale and pilot plant infrastructure with the associated highly qualified personnel for long period of time. It is likely that only companies of a certain size can sustain this level of expenditures through the ups and downs of world oil prices.

**Corporate Oil Sands R&D**

Primary research conducted for the purpose of this study also included an extensive review of public documents submitted by oil sands companies to financial regulators, shareholders and the EUB. It also included interviews with specific companies.
However, as mentioned earlier in this report, specific information obtained during those interviews is not reproduced here.

Table 19 presents a summary of this investigation and represent best estimate of privately funded oil and gas R&D between 1999 and 2004 as determined by the authors. All the data shown for companies named on Table 19 was obtained or estimated from public sources. The complete list of companies for which data was obtained in analyzes is as follows:

- Syncrude
- Imperial Oil
- EnCana
- Shell Canada
- Suncor Energy
- Deer Creek Energy
- Husky Energy
- Petro-Canada
- Canadian Natural Resources Limited
- Nexen
- OPTI
- JACOS
- ConocoPhillips Canada
- Total
- BA Energy
- UTS Energy
- BlackRock Ventures
- Petrobank
- Devon
- Synenco Energy
- Albian Sands
- Chevron
- Connacher Oil & Gas
- Fort MacKay First Nation
- MEG Energy
- North West Upgrading
- Paramount Resources
- Western Oil Sands

The data is presented graphically on Figure 19. The same growth pattern noted in the information reported by Statistics Canada and Research InfoSource is repeated here: a significant growth in privately funded oil sands R&D occurred between 1999 and 2004. On average, corporate oil sands R&D expenditures during the years covered by this study were $146 million per year.

It is also notable that only a few companies are responsible for most of the research and development. The top 8 companies account for 80% to 90% of all oil sands R&D in each of the years surveyed.

It would be reasonable to anticipate that the pattern of steadily increasing amounts of money dedicated to oil sands R&D will continue in the coming years. Oil prices are expected to remain at high levels. Another element of evidence is the uptake by industry of Alberta Energy's IETP program introduced last year to support demonstration pilots for new technologies in Alberta. For 2005 and future years, the amounts already announced under IETP for oil sands pilots alone are:

- $39.7 million from Alberta Energy;
- $92.6 million from industry;
- For a total of $132.3 million of new oil sands demonstration pilots.
Full uptake of the program would lead to a total of $666 million of new demonstration pilots in Alberta in years to come.

As noted earlier in this report, in the last five years the average amount of public funds dedicated to oil sands R&D was on average $23 million per year. Therefore, the $146 million per year spent on average by industry represent a ratio of if 6.3 to 1 industry to government funding. It appears that industry is carrying most of the burden for oil sands R&D.
### Table 19 - Oil Sands Privately Funded R&D Expenditures ($ million)

<table>
<thead>
<tr>
<th>Percent 2004 Production from Oil Sands</th>
<th>1999</th>
<th>2000</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>Information Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Syncrude</td>
<td>100%</td>
<td>$27.0</td>
<td>$37.0</td>
<td>$48.3</td>
<td>$52.3</td>
<td>$50.4</td>
<td>$34.2 Research InfoSource</td>
</tr>
<tr>
<td>Imperial Oil</td>
<td>35%</td>
<td>$24.2</td>
<td>$19.3</td>
<td>$24.9</td>
<td>$22.4</td>
<td>$22.1</td>
<td>$24.5 Annual reports;35% Oil Sands</td>
</tr>
<tr>
<td>EnCana</td>
<td>7%</td>
<td>$1.4</td>
<td>$17.9</td>
<td>$19.5</td>
<td>$17.6</td>
<td>$15.6</td>
<td>$22.3 InfoSource; 10% Oil Sands plus pilots; Foster Creek and Christina Lake SAGD pilots in 2000-02; Solvent addition Christina Lake pilot 2003; Brintnell water flood 2003; IETP: VAPEX Suffield $ 3.3 million; EnCAID Cold Lake $9.5 million; Low pressure SAGD lab test $360,000;</td>
</tr>
<tr>
<td>Shell Canada</td>
<td>65%</td>
<td>$9.8</td>
<td>$4.6</td>
<td>$3.3</td>
<td>$3.9</td>
<td>$6.5</td>
<td>$18.2 Annual reports; 65% Oil Sands</td>
</tr>
<tr>
<td>Suncor Energy</td>
<td>87%</td>
<td>$10.9</td>
<td>$10.3</td>
<td>$6.6</td>
<td>$14.8</td>
<td>$17.6</td>
<td>2000-02 per Suncor Performance Indicators; 2003 and 2004 at 80% of Research InfoSource; IETP Low pressure SAGD pilot $10.5 million</td>
</tr>
<tr>
<td>Deer Creek Energy</td>
<td></td>
<td>$1.0</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$6.0</td>
<td>$16.5 Per annual report: Joslyn low pressure SAGD $13.3 million; MSAR trial</td>
</tr>
<tr>
<td>Husky Energy</td>
<td>0%</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$1.0</td>
<td>$6.0</td>
<td>$11.0 U of C Chair; AACI; Tucker pilot</td>
</tr>
<tr>
<td>Petro-Canada</td>
<td>4%</td>
<td>$4.4</td>
<td>$2.0</td>
<td>$1.2</td>
<td>$6.2</td>
<td>$13.0</td>
<td>$8.4 Annual reports; 20% Oil Sands; MacKay River pilot</td>
</tr>
<tr>
<td>All others</td>
<td></td>
<td>$6.1</td>
<td>$20.6</td>
<td>$21.1</td>
<td>$30.0</td>
<td>$30.5</td>
<td>$32.9</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$73.8</strong></td>
<td><strong>$113.2</strong></td>
<td><strong>$129.5</strong></td>
<td><strong>$141.0</strong></td>
<td><strong>$159.9</strong></td>
<td><strong>$185.7</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: Portfire Associates from company public information
**Figure 19 - Oil Sands Privately Funded R&D Expenditures**

Source: Portfire Associates from company public information

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**Desired Outcomes for Oil Sands R&D**

**Research Stage**

The information for both publicly funding and privately funded R&D was analyzed with respect to the stage of research. The results are shown on Figures 20 and 21. Publicly funded R&D is mostly directed at applied research and fundamental research. Demonstration pilots form a relatively small fraction of publicly funded R&D. By contrast, privately funded R&D is mostly directed at demonstration and applied research. Fundamental R&D accounts for only an estimated 7% of privately funded research. Industry is driven by business and operational goals and therefore dedicates most of its R&D dollars to applied research that is aimed at resolving known technical challenges and demonstration pilots which are aimed at proving and further developing at the commercial scale technologies that have been developed in the laboratory or at the bench scale.
Figure 20 – Research Stage for Publicly Funded R&D

- Fundamental, 38%
- Applied, 47%
- Demonstration, 15%
Stage of Resource Development

The information collected was also analyzed with respect to this stage of resource development. Figures 22 and 23 show the results of this analysis. Publicly funded R&D and privately funded R&D both dedicate the majority of their investment to the development of new or improved technologies for recovery of bitumen. While some of the work is done in laboratories and at the bench scale, most of the budgets are spent on field pilots.

The public sector however, funds more research for upgrading than the private sector. The reason is the important contribution made by NCUT in Devon Alberta, which is a publicly funded federal government laboratory focused on upgrading research.

At least one company conducts R&D for upgrading in Alberta. The purpose is to gain a significant amount of know-how on improving yields from upgrading units. Another target has been extending the time between turnarounds. Upgrading R&D also extends to improving catalysts for hydrotreating. For some companies, upgrading technology development does not involve R&D but is limited contracting pilot plant work to confirm yields and other technical data for bitumen produced by company leases. The purpose of these pilot studies is not to advance or develop new technology but to confirm that
bitumen from specific oil sand leases is compatible with proposed upgrading technologies from specific vendors. It is also to obtain accurate technical information such as yields, quality and performance in order to accurately design commercial scale facilities. Many companies participate in joint industry studies such those of the Heavy Oil Upgrading Task Force (HUTF) led by the government of Alberta.

![Figure 22 – Stage of Resource Development for Publicly Funded R&D](image)

The level of environmental research is similar for both the public and the private sectors and falls between 10% and 20%. Water and soil are the most frequently mentioned topics for environmental research. Environmental projects related to vegetation, soil and water reclamation are conducted. Air quality issues appear to receive less attention.

Water intensity is an important area. Although companies typically do not use all of their water allocation from the Athabasca River, R&D program are aimed at reducing water usage by recycling and reusing water. R&D is conducted for reducing water use and increasing the amount of recycled water and for reducing the size of tailings ponds.
Energy intensity is an important research area for the industry. Over the years, surface mining operations have succeeded in lowering the temperature for the extraction process. Originally the temperature of the hot water process was 80° C. New processes operate with warm water at 50° C. The recent LEE process (Low Energy Extraction) had originally targeted 25° C but the temperature needs to be 35° C for most ore bodies.

With respect to greenhouse gas emissions, oil sands companies are not working actively on new technologies. However companies are part of coalitions that are studying CO₂ sequestration and a potential CO₂ backbone pipeline from the Fort McMurray area to central Alberta where CO₂ could be used for enhanced oil recovery. Greenhouse gas projects are also associated with energy efficiency projects.

**Deposit Types**

With respect to the types of oil sands deposit that are targeted by R&D, most of the work is for deposits that are recoverable by in situ thermal technologies such as SAGD and CSS, as shown on Figure 24.
Operators of oil sands mines conduct R&D for improving the process, particularly for reducing the energy and water intensities of the water extraction process. Little R&D, if any, is done for recovering bitumen from ores that contain low amounts of bitumen. These ore bodies are currently left in place and not mined. R&D is not conducted specifically on methods to recover bitumen under tailings ponds, other than having identified that these deposits exist and that they are potentially recoverable in the future. There does not appear to be R&D work on developing technologies that would allow surface mining to go to greater depth than the current 40-50 m.

SAGD demonstration pilots appear to command the lion's share of budgets. Over the last few years several demonstration pilots are aimed at improving SAGD operations have been constructed and operated. These efforts have sought to develop technologies such as:

- The adaptation of SAGD to specific reservoir conditions;
- Developing an understanding of operational parameters such as steam chamber growth, the impact of shale or clay layers, adjustments for water zones; steam to oil ratio, etc;
- Low-pressure SAGD for shallow oil sands;
- Artificial lift technologies for low-pressure SAGD;
- The addition of solvents and diluent to the steam in SAGD operations in order to enhance performance and reduce energy intensity;

Other significant demonstration pilots have been for the VAPEX process, for improvements to the CSS process, particularly during later cycles, water floods for
improving the recovery factor of the cold primary production of bitumen. More recently, technologies aimed at re-pressurizing depleted or low-pressure gas caps, and at finding technical solutions for the gas over bitumen issue have started to become to object of demonstration pilots.

Companies are also investigating the impact of bottom water and shale inter-layers on bitumen reservoirs. Other technologies such as borehole mining were looked out before. However, currently CSS and SAGD remain the main focus.

Shallow deposits are the major type of inaccessible deposits that are being targeted, mainly with low pressure SAGD. No R&D was identified that was directed at bitumen in carbonate formation or at deposits with insufficient cap rock, shale or clay barrier. Only a small amount could be deemed applicable to thin oil sands.
INDUSTRY PERSPECTIVES

Current R&D Capacity for Oil Sands

The R&D capability of the oil industry in Alberta has been significantly diminished from what it was in past decades. Laboratories at Petro-Canada, Shell and Imperial Oil have either been closed or reduced in scope. Some capabilities appear to be returning, particularly in partnerships with the universities.

Most oil companies are not specifically focused on oil sands. One exception is Syncrude which has a long history of conducting R&D for oil sands. The R&D division at Syncrude started over 40 years ago in 1964 and is still very active today. Most companies draw on a heritage in conventional oil and gas application. Their background is the development and adaptation of technologies such as drilling, completions and delineation for conventional oil and gas fields. They are now attempting to transfer these skills to the oil sands.

Before conducting field pilots, companies will do bench scale trials. Companies are working with the Alberta Research Council to conduct applied and bench scale research on a contractual basis. However, there might be a shortage of equipment and space for bench scale work.

Oil sands companies often come to the conclusion that the business case for developing new technology is not appropriate for an operating oil company, particularly a smaller one. Generally oil companies have determined that they cannot get an adequate return from the developing new technology. Operating companies tend to be adopters and modifiers of existing technologies. They leave the business of R&D and technology licensing to specialized technology companies. They are adopter of technologies. For example, sources of technology for upgrading are the large engineering firms such as ABB, Stone & Webster and others.

Companies often consider buying technology and conducting work at the bench scale to adapt purchased technologies for their needs. For upgrading, most companies would consider licensing an existing commercial technology package and would not conduct significant R&D.

Future R&D Needs

Surface Mining

One area of interest for new surface mining technology has been smaller scale mining operations. Some companies are looking at technology options for scaling back the size of projects while controlling costs. Other targets are new technologies for exploiting lower quality ores and for producing dry or concentrated tailings, which would reduce water usage considerably.

One challenge for some surface mining leases is that oil sands deposits are in pockets. Companies may need to investigate ways to conduct decentralized mining operations.
Upgrading
A gap is a technology for partial upgrading. Hydrogen addition must be used during upgrading in order to stabilize the upgraded bitumen. This means that the cost of partial upgrading is not much reduced as compared to full upgrading. Therefore, the only choice currently is no upgrading or full upgrading.

Other goals could be to achieve breakthroughs in upgrading technologies such as non-thermal coking methods that would use far less energy or such as gasification at 800°C which is far less than current commercial temperatures.

Alternative Fuels
Research on alternative fuels is mainly driven by high natural gas price costs. Currently companies are vulnerable to the difference between bitumen pricing and natural gas costs.

Alternative fuels such as a bitumen emulsion are also being evaluated. In order to apply this technology, a gas cleanup module needs to be built to control NOx and SOx emissions. Air emissions are an important consideration when burning bitumen as fuel instead of natural gas.

Processes to make hydrogen or fuel gas from coke are also of interest. For this purpose companies are considering gasification.

Environmental
In the environmental areas a major goal is to minimize the impact of tailing ponds. This implies that the focus of future R&D should be to use less water and to develop non-aqueous technologies.

Research on wetlands is also important. Wetlands exist on oil sands leases and often a condition of EUB approval is maintaining the functionality of the wetland. Therefore companies are members of multi-stakeholder committees that support research in understanding water soil interactions.

Materials
One of the areas for R&D is materials. For example in surface mining there is a big impact on cost and reliability from factors such as erosion and corrosion. Improvements in materials of construction would be important to reduce sustainable sustaining capital costs in mining operations. Another approach is improved coatings and steel alloys.

Collaboration
Industry and companies differentiate between types of research and development programs. Those programs that target core technologies at the heart of their business would typically be done in house and offer little opportunity for collaboration. However, programs that are exploratory in nature or are concerned with non-competitive areas such as environmental research are available for collaboration.
Companies collaborate with different research groups in Alberta and around the world. Examples of industrial collaboration include centres at the University of Alberta and the University of Calgary, the AACI program at the Alberta research Council, and collaborative projects at NRC and NRCan.

For some companies, collaboration is more than funding. Company researchers are personally involved in university research projects and collaborate with academic researchers. Industrial partnerships with universities are also a mechanism to leverage government funding.

While companies participate in collaborative approaches, the issue of intellectual property often gets in the way of effective collaboration. With respect to core technologies, most companies will insist on owning intellectual property. This often precludes collaboration with universities and government laboratories who also insist on owning intellectual property. One of the barriers with collaborating with universities and government laboratories is that they want to own the intellectual-property. Industry does not think that this is appropriate with respect to core operating technologies.

In general, companies feel that intellectual property is overvalued and constitutes a barrier to collaboration. The cost of protecting and maintaining intellectual-property is often underestimated.

In areas that are not core to the company’s operation, such as environmental and other matters, companies find it easier to collaborate because they do not need to own intellectual property in these areas. Areas for collaborative R&D include: environmental technologies, monitoring, improvement to tailing ponds, method for densifying tailings and technologies for making water available for discharge.

Oil sands companies focus their intramural programs on proprietary applied and demonstration research. They tend to collaborate on fundamental research with universities. Sometimes, applied research is done with contract research organizations such as the Alberta Research Council.

**Sharing Operating Data**

While it would be valuable for companies to share operating data with each others in order to speed up the industry learning curve in areas such as SAGD, most companies are reluctant to share operating data for several reasons:

- It may have an impact on their competitive position opposite their competitors.
- There are also concerns with regulatory impact. In the energy industry, companies are committed to meet certain operating targets that are part of their operating licenses. Companies concerned that sharing operating data may expose them to the regulator.
- There are general concerns about contravening antitrust laws.
- Another concern for companies is the potential for excess development in the industry, resulting in oversupply of bitumen, but also resulting in excessive demand for scarce resources such as labour and other inputs.
However there could be an opportunity for a neutral third party to collect operating data on a confidential basis and report back information that is sanitized and represent industry averages. Benchmarking studies done by a neutral third party would be valuable. AACI, which is operated by ARC, is an existing forum for sharing SAGD information between operating companies.

There is interest in building a generic oil sands extraction pilot facility that would be mobile and available to different surface mining operations in order to evaluate processes and address issues that are specific to their site.

The Role of Government

The IETP program introduced by Alberta Energy is viewed as a good program. IETP is encouraging commercialization of recovery technologies. However it is now facing issues with respect to public disclosure of reports. If the program would cause a company to lose control over intellectual property, companies would not be interested in participating.

Twenty years ago, university R&D was made relevant by collaboration with industry. However now the pendulum has swung completely to applied research. The mix between fundamental R&D and applied R&D is not appropriate at the moment. At the present time, universities, the Alberta Research Council and the government laboratories in Devon are all focusing on applied research. Not enough R&D is done on fundamental issues.

Funding and resources need to be dedicated to fundamental R&D in order to fill up the tank of ideas and initial developments. Industry is not appropriate for fundamental R&D because of the high-level a risk and the long-term payout. This is an area for government, universities and government laboratories. They should focus on long-term R&D and fundamental challenges. Companies earn a profit by developing resources. They are not focused on technology development and an earning a profit from technology licensing.

AOSTRA reports and files are accessible through AOSIS which is operated by AERI. AOSIS also contains reports produced by ARC and the AACI program as well as reports produced by universities as part of the COURSE program. What are required are more resources and funding for this information management and dissemination activity. Confidentiality issues exist but could be resolved if resources and funding were made available to address them. The information is very valuable. It is also important to proceed with this in the short-term because many of the people involved with AOSTRA 20 years ago are now starting to retire. It is possible that PTAC may have a role in this information management process. Therefore, more funding and people should be provided for AOSIS and ALIS in order to disseminate AOSTRA information. Industry could provide some of this funding.

Funding models such as the one that was used in United States for the Gas Research Institute (GRI) could be pursued. In this approach, a levy was collected on natural gas moving through pipelines in order to fund public R&D on natural gas. Similarly, the US Department of Energy appears to have a successful model for R&D funding. The US
DOE will fund industry to conduct R&D. However, a condition of that funding is publication of the results in a timely fashion.
KEY MESSAGES

The key points that we made by this report can be summarized as follows:

- The oil sands are a large resource by Alberta standards. The conventional oil and natural gas sector has served Alberta well. Alberta’s bitumen resource is larger than conventional oil and natural gas combined. Alberta’s energy future is with the oil sands.

- Alberta oil sands are also a large resource by world standards. Because of the oil sands, Alberta is ranked second in the world for the size of oil reserves, behind the reserves of conventional oil of Saudi Arabia. The Alberta oil sands are a world class resource.

- Alberta oil sands will last a very long time. Even after production rates are increased three to five times current rates, Alberta’s established reserves of bitumen will still last for a century.

- There are no commercial recovery technologies that are applicable for more than half of Alberta's bitumen resources. The current build-up of oil sands developments is based on less than half the resource.

- Bitumen deposits for which there are no commercial technologies and therefore a recovery factor of zero are:
  - Bitumen in carbonate formations;
  - Deposits too thin for commercial thermal processes;
  - Deposits with insufficient cap rock, shale or clay barriers;
  - Deposits too deep for surface mining but too shallow for SAGD; and,
  - Deposits in communication with low pressure gas cap

- Bitumen deposits for which there is no recovery factor offer a significant opportunity that requires the development of new technologies by investment in R&D.

- Current commercial technologies recover only a fraction of the bitumen volume in place. A second, related, significant opportunity is the development of improved technologies to increase recovery factors, particularly for deposits exploited with cold primary production.

- Current commercial technologies are faced with significant technical challenges for which technology improvements are required:
  - High usage of natural gas;
  - High usage of water;
  - High requirements for diluent; and,
  - Environmental impact, such as tailings ponds and emissions of greenhouse gas.
- The current level of public funding for oil sands R&D is relatively small as compared to:
  - The levels spent by governments in the 1980s through AOSTRA; Current support for oil sands R&D by the provincial and federal governments combined is approximately $23 million per year and is less than half the amount spent by the Alberta government on AOSTRA from the mid-1970s to the mid-1990s.
  - The level spent currently by industry; Industry spent an average of $146 million per year on oil sands R&D between 2000 and 2004, or 6.3 times the level spent by the provincial and federal governments combined.

- Privately funded R&D was curtailed during the last decade because of low oil prices. However in the last few years funding levels have come back and stood at a high of approximately $185 million in 2004. Most of industry's R&D budgets are earmarked for demonstration pilots, and for applied research.

- A considerable amount of technical information resides in old AOSTRA files. This is a depreciating asset that should be made to contribute before it is too late.
The following recommendations are made for further consideration:

1. The level of R&D funding by governments and industry should be increased to become commensurate with the wealth generated by the resource. The recent IETP program is acknowledged as an important milestone. The future prosperity that optimal development of the resource would return to Alberta in terms of increased economic activity and government revenue is huge.

2. A joint government and industry consultation should be undertaken to outline a clear technology vision and strategy for the whole resource. While individual companies may have a long term R&D strategy for their areas of operations, leadership from the government of Alberta, as the resource owner, is required for deposit wide technology challenges, including bitumen deposits for which there is no recovery factor, increases in deposit wide recovery factors, and regional environmental issues.

3. The vehicle for technology vision and strategy development should be found within existing government and industry technology organizations and agencies. Policy should avoid creating a new agency.

4. A joint government-industry funding vehicle should be considered to support deposit wide technology programs. Funding should be long term and substantial.

5. Funding for deposit wide oil sands R&D should be provided, in part, by oil royalties as a sustaining reinvestment to maintain and improve the quality of the oil sands resource.

6. The existing capacity for R&D in industry, universities and government laboratories should be utilized. Recognition should also be given to the fact that a significant amount of R&D capacity resides in industry and that industry continues to be the primary vehicle for demonstrating and commercializing oil sands R&D. Existing R&D organizations need to remain relevant, creative and coordinated in order to warrant funding.

7. A program should be initiated to place old AOSTRA files in the public domain for use by existing researchers before obsolescence and to avoid spending public or private funds on repeating work that was done 20 years ago.
REFERENCES


Alberta Energy and Utilities Board.


