Conventional Heavy Oil R&D Needs Including GHG Intensity Reduction

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Acknowledgements and Disclaimer

About the Climate Change Technology and Innovation R&D Initiative (CCTII)

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Disclaimers

This document is **intended as an initial assessment** of technology needs and potential needs assessment processes. Any technologies discussed or referred to are intended as examples of potential solutions or solution areas and have not been assessed in detail or endorsed as to their technical or economic viability.

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1. Executive Summary

Conventional heavy oil in Canada is mainly produced from deposits located in east central Alberta and west central Saskatchewan. The heavy oil deposits are deeper and thinner than those found in Bitumen or oil sands production areas, and the produced oil is slightly lighter, which allows it to flow at reservoir conditions, making primary production possible. Over the past 15-20 years production of heavy oil has grown rapidly, due to an increased use of the Cold Heavy Oil Production with Sand (CHOPS) recovery process, and the introduction of Progressing Cavity Pumps (PCP's) and horizontal wells. In 1996, conventional heavy oil production accounted for 25% of Canada's oil production and bridged the gap between the decline of light oil and the rise of oilsands production. In 1998/99, estimates were that the conventional heavy oil in place is 26 billion barrels, however, recoveries are only 5-10%, so a considerable amount of the resource awaits the development of new technologies or more favourable economics.

Current production is more Greenhouse Gas (GHG) intensive than conventional light oil, mainly as a result of venting of the methane produced with the heavy oil. Venting is now being discouraged by provincial regulators, however, until recently, producers and regulators viewed it as being economically unattractive to conserve. Provincial regulations do not require that gas be flared if it is non-toxic, does not generate odours or is uneconomic to conserve. Carbon dioxide emissions, from conventional heavy oil production, are lower than for thermal bitumen production, but it is expected that emissions intensity will increase if oil recovery is to be increased from current levels. A few thermal steam operations have been attempted, and some remain in economic operation, even though the heavy oil deposits are considered too thin to allow for widespread use of existing thermal recovery processes. Unlike oil sands development areas, the heavy oil production areas are well established, with oilfield services and a locally based operations workforce. The existing infrastructure would allow conventional heavy oil to continue, supplementing oil sands and light oil production, if new technologies are developed, or existing technologies adapted.

With input from various industry experts and stakeholders, forty-one potential R&D initiatives have been identified for the conventional heavy oil sector, covering a wide range of technical and motivational needs. A primary need, is to better support and encourage efforts to understand the reservoir, impacts of current recovery and operating methods, and to initiate work to start defining the sector's future. Currently there is little understanding of the impacts and expected life of the current recovery process, and there are a great number of questions about how current operations will determine what is achievable in the future.

From a greenhouse gas point of view there are some initial efforts, which could result in major reductions in GHG emissions in the sector, that will be influenced more by motivation than by technology. Reductions in emissions by reducing vent gas, improving tank heater efficiencies and reducing trucking activity, should all be achievable with current technology at reasonable, present value based, economic returns.

For sustainable results that will improve the economics of the sector, while reducing environmental impacts, and supporting those dependent on the industry, R&D efforts must focus on enhancing understanding of what is happening in the ground. Without that understanding, the future of the sector may be compromised, and much of the resource will remain unexploited.

Based on a rough prioritization effort for this study, the top five R&D priorities, that combine benefits of GHG mitigation and sustainable production, are:

1. **Collection and Utilization of Methane** – With rising gas prices and industry being forced to look at marginal gas resources, like coal bed methane or hydrates, it makes little sense to continue to vent gas that can be conserved at a reasonable economic return. The fact that these methane vents are also a major source of GHG emissions, increases the incentive to move ahead quickly on reducing them. Most of the CHO methane sources should be economically recoverable in the near-term with existing technology, even though these opportunities are not as attractive as other oil and gas investments, which provide a better return on capital.
2. **Water Influx** – Most CHO production ends in a flood of water, yet very little is known about where the water comes from in the reservoir, or how and why it suddenly breaks through. This issue is potentially a key indicator of the sector's future that will likely lead to greater insights in many of the identified R&D areas, allowing further rational and efficient development of the CHO resources in Alberta and Saskatchewan. Efficient development will lead to lower future GHG emissions as well as increased recovery of the resource.
3. **Transportation – Pipeline Gathering Systems** – Currently most oil, water and sand, produced in the conventional heavy oil sector, is trucked from individual wells, or small clusters of wells, to centralized facilities for treatment and transfer to sales pipelines for oil, or disposal of water and sand. Trucking is flexible, and low in capital investment for producers, but has high operating costs, GHG emissions and significant environmental impacts in the near-term. In the medium to long-term, conversion to pipeline gathering is a necessary change for the industry to allow continued production, as more complex processes and methods become necessary, and containment of produced fluids and gases will be critical to sustainable operations.
4. **Impacts of Intentionally Producing Sand** – Intentionally producing sand has allowed CHO production to grow, however, the cost of this growth is not yet known. The lack of understanding of sand production impacts, is the root cause of most of the recovery uncertainty for the sector, and makes it all but impossible to predict future production from this resource. This ultimately impacts GHG emissions, as intensity changes with the processes used, and the total emissions also vary with how much of the resource is recovered.
5. **Extend Low Energy Primary Recovery** – As primary recovery is generally less capital and energy intensive, than other potential recovery methods, the best combined result of R&D efforts would be to develop ways to extend primary production as long as possible. The fact that conventional heavy oil

is producible at high rates, with an unusual production mechanism like CHOPS, means that there may be options out there if sufficient understanding can be gained from field investigations and focused analysis.

Attacking the above priority R&D needs, will take more than funding University research, as it will require systemic changes to the way the sector operates, how it is regulated, how R&D is funded and who does the work. The focus of R&D will be to learn about the current operations, so that the appropriate reservoir, drilling, completion, production and surface technologies can be adapted to meet the needs. To ensure that the benefits of new technology are fully realized, it will also be necessary to assess the incentives and motivation for producers, regulators, innovators, vendors and other stakeholders to champion, and support, the implementation of technology once it has been developed.

2. Background – Current Situation Assessment

2.1. Conventional Heavy Oil Resource Description

The term, conventional heavy oil (CHO), is loosely used to cover a range of heavy oil and bitumen production that is at a depth and temperature, which allows the resource to be developed with only primary pumped production. The main conventional heavy oil producing area straddles the Alberta/Saskatchewan border and includes producing fields within a 100-200 km radius of Lloydminister. The deposits are generally between 800-1200 m in depth with reservoir temperatures in the range of 20-30 degrees Celsius. In the past 15-20 years production of CHO has been greatly increased (Figure 2.1) by the discovery that oil rates and volumes produced can be increased by allowing sand to be produced with the oil, through a process referred to by some as Conventional Heavy Oil Production with Sand (CHOPS). Previously conventional wisdom was that sand should be kept out of the well by use of screens, as the traditional rocking beam type pumping system was unable to handle high sand volumes. The need for increased sand production led, in turn, to the innovation of utilizing rotating Progressing Cavity Pumps (PCPs), that are better able to move the sand, and suffer fewer problems in the presence of solution gas and foam, normally produced with the heavy oil.

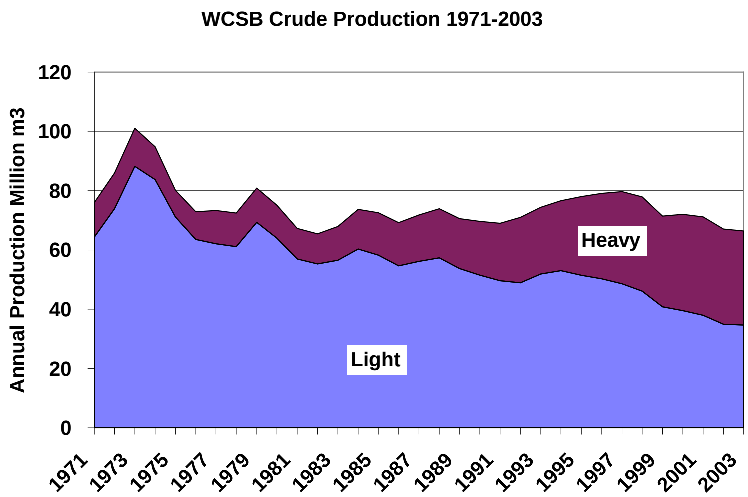


Figure 2.1 – Comparison of WCSB Crude Production (Source CAPP)

While current production levels are high; oil recoveries are generally only 5-10% of the Initial Oil in Place (IOIP) compared to an average 25-30% recovery for light oil (see Figure 2.2). Production is maintained by intensive drilling of new wells to replace those that stop producing, due to water breakthrough, high well maintenance costs, or loss of reservoir energy to drive production. Eventually, there will be no new locations available to drill, and production rates will decline, unless alternate production methods, and/or higher heavy oil prices, increase the recoverable reserves.

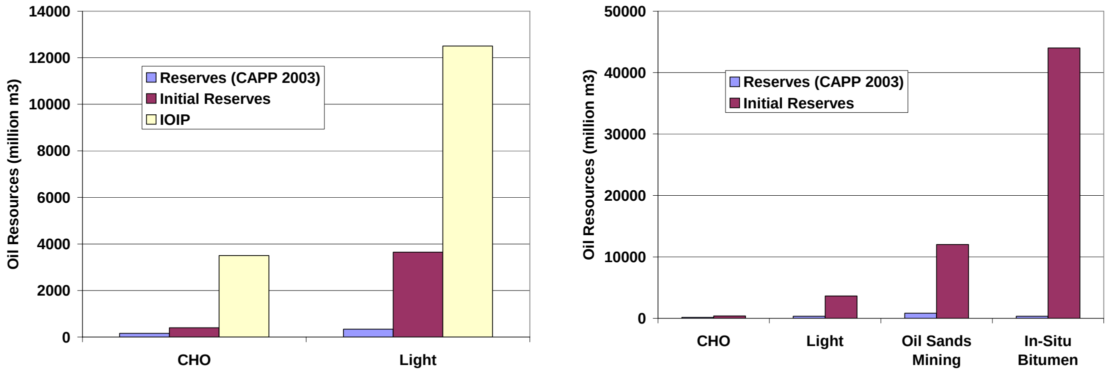


Figure 2.2 – Comparison of CHO to Light Oil and Potential Oilsands Reserves in the WCSB (Source CAPP)

2.2. Sector Characteristics

The CHO sector has some unique characteristics that impact resource development and R&D efforts.

Lease Ownership and Collaboration - Like conventional light oil, mineral rights to CHO leases are obtained either from the Crown or Freehold Royalty owners, usually in 1/16th of a square mile (40 acre) parcels. However, unlike most conventional oil operations, there is no inherent incentive, such as common facilities, enhanced oil recovery projects, or pipelines, to encourage joint management of producing assets, or R&D collaborations. CHO wells produce into lease tanks, and the production is transferred by truck to regional oil treatment, water treatment/disposal facilities and production pipeline stations, so wells are operated individually, or in small groups or clusters of 4-7 wells. This situation is also very different from oilsands leases in Alberta, which may be thousands of acres in size, and are leased by the Crown to individual companies, or consortia, for orderly development. In some regulated areas, such as Alberta's draft Guide 60 on flaring and venting, or where there is co-ownership of an overlying gas pool, companies in an oilfield are being required by regulators to collaborate, for the common good and to conserve the gas resources.

Divergent Corporate Interests - Mergers, acquisitions and consolidation of CHO operations, over the past 10 years, have generally resulted in major producers controlling larger percentages of some fields, however, few fields are 100% controlled by a single company. Producers in a given field, while generally all wanting to increase recovery from their leases, often have divergent corporate strategies and priorities, operating practices, and application of technology. Capital investment per well is generally small, and permanent facilities on leases are kept to a minimum, since wells may stop producing soon after start-up, and have to be abandoned.

2.3. Economic Factors

A large and on-going issue in the CHO sector, is the lower market value of heavy oil compared to light oil, known as the light/heavy differential or spread. Figure 2.3 shows the absolute, and percentage, discount variation in light/heavy prices with time. The differential is driven by upgrader availability vs. heavy oil supplies in North American markets. The differential puts pressure on producers, in this sector, to keep capital and operating costs very low, in order to maintain the relative profitability of CHO compared to other investment opportunities, in natural gas, light oil and oil sands developments. While the differential also impacts bitumen production, from oil sands leases, royalty concessions for the larger oil sands developments, and the greater predictability of oil sands production, help to negate some of the price differential impacts. As a result, CHO production has a lower perceived value, in comparison to thermal bitumen or novel enhanced heavy oil recovery processes, which attract royalty breaks, or other incentives to encourage development and defray start-up risk.

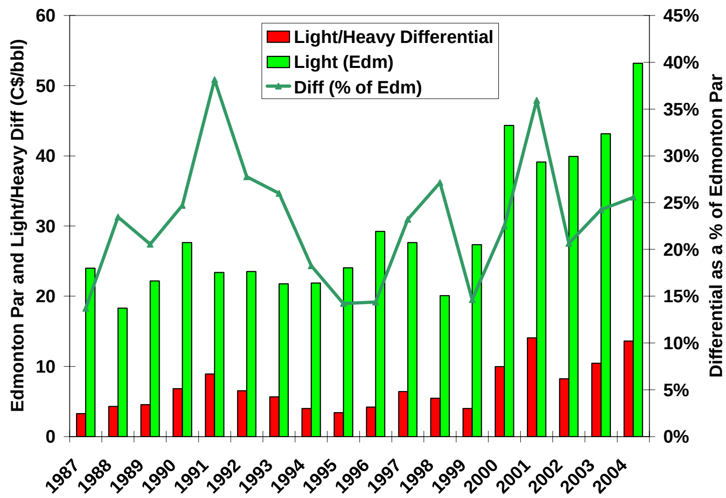


Figure 2.3 – Disadvantage of Light vs. Heavy Oil Market Prices (Source CAPP)

2.4. Safety and Environmental Factors

Safety – As with any industrial activity, involving heavy equipment and energy streams, the CHO industry places a high priority on operations safety. The first concerns, normally mentioned by residents in the region, are related to the high volume of trucks and rigs on rural roads and highways. Dust and road damage, due to high truck use, are chronic concerns. As the energy industry contracts out trucking services to many small trucking firms, we were unable to find any central database, to provide statistical information, on CHO related safety incidents. On the well leases, safety issues focus on standard safety concerns related to: stationary rotating equipment, hydraulic systems, gas fired engines, electrical power, truck traffic and gas fired heaters in oil tanks.

Environment – Key environmental issues in addition to GHG emissions, which are covered in the next section, include:

Land – CHO operations tend to be in agricultural areas with small grain or cattle operations. Traditional single well leases with access roads take up considerable acreage, and require reclamation when wells are abandoned. Spills of salt water can hinder later agricultural use, and often oily sand material from tank clean outs and spills is used for dust control. Oily solids or sludge material, that is surplus to road surfacing needs, is often transported for disposal in salt storage caverns in the region, which allows for some recovery of the waste oil. Lease sizes, after drilling, are minimized to allow a return of some of the lease to agricultural uses, with provision for protection of livestock through cattle guards around well-heads, and "cattle gates" on lease roads. Lease berms or containment structures are sometimes used if there are concerns about oil or saltwater spills, however, the need for heavy truck access to the lease tanks often reduces the effectiveness of lease containment.

Water – Produced water from the wells is trucked from the leases to central treatment and disposal sites. The water is saline brine, so care must be taken to minimize spillage, on the lease and roads, in natural and agricultural areas. Fresh water use is generally limited to a few water floods, and thermal steam operations, which may use water from the North Saskatchewan River.

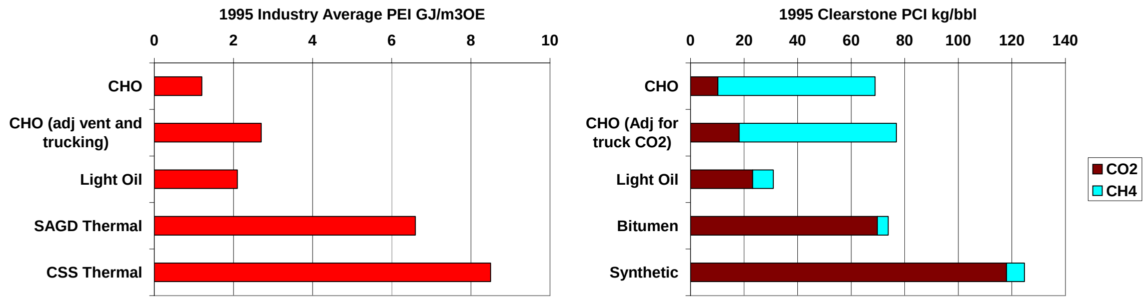
Air – The main air emissions are: methane from well venting, and emissions from natural gas combustion equipment and diesel trucks. If vented gas contains any odour causing components, principally H_2S, conservation or flaring is usually required. Combustion emissions are dependent on the type of equipment installed at a site, or used by truckers, the type of fuel used, and how well the equipment is maintained. Engine issues would be similar to other transportation and natural gas production operations, however, the simple, low-cost emersion tank heaters used in heavy oil operations are inefficient and rarely optimized to match well production conditions. Tank heater efficiency is generally assumed to be in the 30-50% efficiency range (based on Higher Heating Values HHV), due to poor control of excess air, poor heat transfer to the oil, and because many heaters become oversized compared to demand, as production levels drop, leading to periodic firing.

2.5. Energy and GHG Intensity Indicators

Energy Intensity - The CHO sector has the lowest production energy intensity (PEI) indicator, of any of the upstream oil production sectors listed in CAPP's 2003 Guide for Calculating Greenhouse Gas Emissions (see Figure 2.4a). Due to the method of calculation, this indicator does not actually cover all the energy impacts of CHO production. The Product Energy Intensity calculation formula, used in the guide, excludes the energy value of methane gas being vented to atmosphere, from all sectors. And the CHO PEI, also excludes energy used in trucking CHO production (oil, water and sand) from the producing wells to treating facilities, which is a basic part of the production process. In other sectors, ignoring these factors has significantly less impact than it does in CHO operations. Based on a vented methane to oil ratio of 28 m^3 gas/m^3 oil, venting would add 1 GJ/m^3OE[1] to the PEI to match the indicated Production Carbon Intensity (PCI) impact of venting. Depending on assumptions of trucking round trip haul distances, and fuel efficiency, the PEI

[1] Calculation based on methane PCI contribution in Clearstone estimate of 59 kgCO2eq/bbl oil = 16.8 kgCH4/m3 oil = 1 GJ/m3 oil. NB. In Alberta measurement improvements caused an increase in vent emissions in 2000 and these had been reduced by 40% by 2003 through vent gas recovery projects. So the exact methane contribution to PCI at any time is highly uncertain.

could increase by 0.3 to more than 0.9 GJ/m^3OE[2] due to haul truck fuel use. Energy Intensities also do not include energy use for upgrading or refining, which are consistently excluded for all upstream oil production sectors, in the CAPP guide. Another potential adjustment, across all sectors, would be to increase the PEI's to reflect the thermal efficiency of power generation, as PCI's include GHG emissions from power generation, but PEI's don't reflect waste energy from centralized power generation systems, which may only be 30% energy efficient, and also ignores power transmission losses.



Figures 2.4a and 2.4b – Comparison of 1995 PEI and PCI Indicators by Sector (Source CAPP except for Adjusted CHO Case Estimated)

GHG Intensity – The CHO sector has a high GHG Production Carbon Intensity (PCI), mainly due to venting methane produced with the heavy oil. Figure 2.4b shows the relative contributions of methane and CO_2 to the CHO PCI. The main factor contributing to high volumes of venting, from CHO, is that the gas produced tends to be sweet, with little or no hydrogen sulphide or aromatic hydrocarbons. As methane is a colourless and odourless gas, that rapidly rises and disperses, it has not been perceived as an emissions problem from a health or safety perspective. Similar emissions, in conventional light oil operations, usually contain other components, which provincial regulations require to be controlled by conservation or flaring. Historically, low gas prices have not made conservation of small methane sources economic, so there was no motivation for reducing vent gas volumes. The rapid increase in natural gas prices, in recent years, has been a major motivator for producers, and regulators, to conserve the vent gas. Generally, venting can be controlled, using similar technologies and practices, which are already used in other conventional light oil operations, for odour control. The motivation for increased conservation has also been somewhat affected by the Kyoto Accord more through awareness of the volumes emitted, rather than to reduce GHG's. Increased monitoring for Voluntary Challenge Reporting (VCR) has increased understanding of the volumes of gas being vented, and the GHG emissions reductions, which could be achieved relatively easily. Most vent reduction activities have relatively rapid economic payouts, if the vent gas can be utilized locally to fuel operations, or generate incremental local natural gas sales. The lack of clear rules and targets, for

[2] Assumed ranges for truck fuel intensity factors – Load size 5-10 m3/load; 100-150 km/round trip including daily returns to base; 50% increment/m3 oil for water hauling to disposal; 50% increment/m3 for sand/sludge hauling to disposal; fuel use 40-60 l/100km for trucks. NB. All these factors vary widely by company, field and truck dispatch patterns, idling time, type and condition of roads and trucks, etc. so figures should be used with caution.

GHG credits or offsets, tends to reduce the priority placed on further reductions in GHG beyond what is required to meet provincial regulatory requirements or economic objectives.

2.6. Security and Societal Factors

In addition to near-term economic, environmental and safety issues, there are other security and societal factors, which should drive new R&D to maintain or expand CHO production, while minimizing negative impacts. These issues cover security of oil production revenues in Alberta and Saskatchewan, economic support to the local region, and other factors that affect smaller sub-sectors of the CHO industry. Three factors are covered below, as examples from the viewpoint from some specific stakeholder groups.

Oil Recovery Limitations – This is best reflected in a working group statement that *"Conventional Heavy Oil is Saskatchewan's Oil Sands"*, which gives an indication of the importance of this sector to the Saskatchewan government and the provincial economy. The significant volumes of heavy oil left behind, if recovery is limited to 5-10% of the resource, is a major prize for the Saskatchewan economy, even though it may be dwarfed by Alberta's oil sands. The 90-95% of the remaining heavy oil resource, could play a key part in Saskatchewan's economic future, so the need for new technologies to exploit it is much greater, than it is in Alberta. The need for New CHO recovery technologies, gives the Saskatchewan Research Council, and other organizations, a clear mandate and focus to generate new ideas enabling exploitation of the potential.

Importance of CHO to Local Economies – Prior to the boom in conventional heavy oil production and upgrading, communities in the region struggled to maintain services, and encourage younger residents to stay and work in the region; much less attract new development and workers from other regions. The past 10-20 years has seen rapid growth in the Border City of Lloydminster, and in other communities in the region, where heavy oil had previously only made a small contribution to the regional economies. The region now has a strong, young and vigourous economy, which could quickly die, if conventional heavy oil production does not progress beyond CHOPS technology. Oilfield businesses and workers, would be forced to relocate to the already over-heated oil sands regions in Alberta, which are more energy intensive than labour intensive, once processing facilities are completed.

Truckers and Pipelines – Due to the past need to truck all production from the wells to central locations, oilfield trucking is a major occupation in the area. However, the drive by producers to minimize operating costs, often means that trucking companies, and owner/operators, are hired on long-term contracts, which may limit their ability to absorb fuel price increases, rising insurance premiums or higher than expected wear and tear on equipment. Meanwhile, some producers are motivated to lower operating costs, through development of pipeline technology to reduce the need for trucking. This results in conflict in the communities over pipeline technology development and its application, even though pipelines would lower energy consumption, operating costs, environmental and safety impacts, and extend the ability of producers to recover more oil. Therefore, technological changes must be developed and presented in a way that will result in win-win solutions for all stakeholders to allow their widespread implementation to proceed.

2.7. R&D Support to the Sector

Despite the considerable prize remaining in the CHO deposits, very little institutional research has been undertaken in this area, as the immense size of the oilsands deposits in northeastern Alberta dwarf the volumes of remaining conventional oil. The main R&D support has come from producers providing ad hoc support, through equipment trials for local innovators, and efforts by universities and others to develop new concepts, which may also allow increased recovery in oilsands areas. However, both groups suffer from a lack of access to solid production, or other operational data, which would allow them to better assess the true value, challenges, constraints and ultimately the need for their innovations or processes.

3. Objectives and Development Process

3.1. Objectives of the Study

This report is part of a larger effort, on Bitumen and Heavy Oil, being managed out of the CANMET Energy Technology Centre in Devon. The study focuses primarily on assessing research and technologies required to reduce future GHG intensity in the Conventional Heavy Oil Industry. Reducing GHG emissions from potential operations is also required, as the sector continues to produce and increase recovery of the heavy oil resource into the future.

3.2. Areas of Focus

This study addresses three key areas, which are relatively unique to Canadian Conventional Heavy Oil production, which have potential to produce results over 3 timeframes, as follows:

- **Near-term (2005-2008) Focus on Methane** – Demonstration, and early adoption of technologies, to reduce methane vent emissions from existing Conventional Heavy Oil primary recovery operations. It is anticipated that this activity could significantly reduce GHG emissions from this sector in time to meet initial Kyoto targets. Progress will mainly be supported, by tightening of provincial regulations to reduce vent emissions, where volumes are shown to be economic to conserve.

- **Medium-term (2005-2020) Focus on Low Emission Thermal Recovery** – Research and development to adapt, demonstrate, and encourage early adoption of thermal reservoir processes currently used in oil sands areas, or not possible to use in oil sands areas, but which might be suitable for the deeper, thinner heavy oil deposits. Conventional heavy oil deposits contain hydrocarbons that are less viscous than bitumen, and are found in warmer reservoirs, so result may be possible with less thermal energy. Lower energy intensity would generate fewer GHG emissions, per barrel of heavy oil, if the energy injected can be utilized more effectively.

- **Longer-term (2005-2030) Focus on Novel Non-Thermal Recovery Methods** – Research and development, demonstration and early adoption of non-thermal reservoir processes, which may be able to take advantage of the unconsolidated and highly permeable nature of WCSB conventional heavy oil deposits. The characteristics of the resource, which allow CHOPS to work, may allow increased recovery, without the need for combustion and consequent generation of greenhouse gases.

3.3. Development Process

Initial Report - PTAC originally proposed to carry out a more detailed study, through literature searches, obtaining input from technology experts, workshops and working group sessions. This was to be supplemented with significant follow-up efforts, to better define the needs and efforts required, in the main technology areas identified. Due to constraints on budget timing and funding uncertainties, it was decided to initially focus on gathering information through working groups and a workshop, to obtain a sense of the broad CHO R&D needs and provide a more defined start point for future efforts. We now envisage that some follow-up work may be required, based availability of funding, to respond to questions, issues or opportunities, which may be raised in the initial report and that the results of this additional effort might be made available through a supplemental report.

Key steps in the initial investigation process were:

- **Working Groups and Workshops to Gather Broad Input** – Key technology focus areas were identified early in the project to allow for a series of working group sessions, and a more general workshop, which were all held in March, 2005. Three half-day working group sessions were held on March 9-10, to look at current CHOPS production and potential future thermal and non-thermal recovery options, and were attended by experts in those areas. A follow-up workshop was held, on March 21, to present working group insights and engage broader input on the potential technology area, specific research objectives, and to prioritize opportunities.

- **Initial Technology Needs Report Preparation** – A final report was prepared containing results for reduced GHG intensity of conventional heavy oil production, based on the working groups, workshops and follow-up activities. This report was distributed in final draft form for comment and peer reviewed by presentation to interested Producer Representatives on September 29th, 2005.

Supplemental Report (Proposed) - PTAC anticipates that further funding may be approved to expand on this initial report, and allow for preparation of a supplemental report focused on high priority issues.

Key steps in the supplemental investigation process would include:

- **Initial Literature Search –** Obtain and review representative or previous work done on the conventional heavy oil sector in Canada, and operations in other countries with similar operations in key research areas.

- **Interviewing and Engaging Key Industry Specialists** – Key contacts would be contacted to expand on knowledge gained through the literature search. Where necessary specialists may be sub-contracted to provide more detailed assessments of specific technologies or technology areas.

- **Further Investigation of Key Needs and Potential Solutions Areas** – Additional work would be conducted to more completely define and describe the technology specific needs, which are most likely to allow maintenance and/or expansion of conventional heavy oil production, while minimizing GHG emissions. An assessment could also be made of the availability of expertise in Canada, to support the research, potential funding needs and sources, and synergies with other research efforts in Canada and internationally.

- **Supplemental Report Preparation** – Report would summarize key learnings from literature searching and follow-up work on key areas, and would contain a summary of key R&D needs areas, with specific details on background, current R&D efforts, R&D capability, funding and other resources or support needed to progress development.

3.4. Areas Covered Elsewhere – As this report is only a portion of the work being conducted for the CCTII program, there were areas of overlap between some technology and R&D areas. Key associated documents, for the Conventional Heavy Oil sector, can be found in two reports prepared by LENEF Consulting, supported by CCTII funding. These reports contain assessments of technologies, many of which could also be applied to CHO operations, as follows:

- **"Bitumen and Very Heavy Crude Upgrading Technology" – March 31, 2004** – Addresses long term R&D issues related to technology development needs for bitumen and heavy crude upgrading. The additional energy use and emissions for upgrading are significant, from both process fuel and hydrogen production, which would double the GHG emissions associated with CHO production (add ~75 kgCO2eq/bbl). Upgrading is important for Conventional Heavy Oil production in three key areas:
  - **Increased Market Value** – the primary reason for upgrading heavy oil is to increase market size and the value of the product to downstream refineries, which are not designed to take much heavy oil. Producing a lighter product would help to reduce the price differential between light and heavy crude production. A major challenge has been that new CHO production can be brought on stream at a much higher rate than new upgrader capacity can be added, and high differentials favour the profitability of the upgraders. As a result, the CHO producers have seen expanded markets, which allow them to produce more, but the light heavy spread illustrated in Figure 2.4 has not been greatly impacted by new upgrader development in the longer term.
  - **Pipeline Transportation** – Heavy oil is very viscous and difficult to transport through pipelines, which is why trucks are used to gather the heavy oil. Options for long-distance pipelining include dilution, field upgrading, or heated pipelines.
  - **Generation of Low Sulphur Fuel Streams** – If large amounts of energy are required for a CHOPS follow-up recovery process, the energy might have to come from combustion of the produced heavy oil. Small-scale upgrading, or return flow from larger upgraders, can provide a source of low sulphur, light hydrocarbon fuel to displace higher cost natural gas.
- **"Bitumen Recovery Technology" – April 30, 2005** – Focuses on In-situ and mining based recovery R&D needs. It is assumed that any technology developed for bitumen may have application in the conventional heavy oil areas, with the major challenge being to adapt the technology to the deeper and thinner heavy oil resource.

4. Identification of R&D Needs

A series of three working group sessions, and an open workshop were held in March, 2005 to stimulate discussion and obtain input on CHO technology R&D needs for the near, medium and long term and in key technology areas. Feedback and input was obtained on the R&D process in Conventional Heavy Oil, in contrast to other oil and gas sectors, and potential methods of improving support to the R&D efforts to achieve desired results. The working group sessions took place on March 9-10, and recognized experts in various CHO technologies were invited to contribute input for an initial screening, which would serve as input for the larger workshop. Some of the working group members were asked to prepare presentations for the workshop, to stimulate discussion of R&D needs. Details of these sessions, including attendees, presentation materials, notes and feedback summary are included in Appendix A, and were also made available on PTAC's website, listed under the Heavy Oil Technical Area at: http://www.ptac.org/techchof.html under "Workshops".

As shown in Figure 4.1, the workshop was well attended and included a solid cross-section of CHO stakeholders.

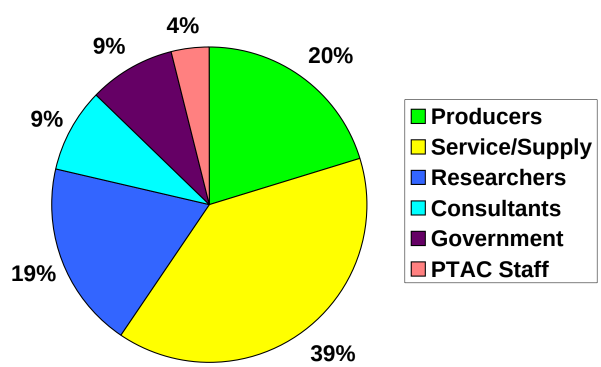


Figure 4.1 – Distribution of Participants at the March 21 Workshop (75 attendees in total)

Working group and workshop participants brainstormed technology research areas, as well as R&D process issues. Attendees were asked, in each case, to select the areas they felt would contribute the most to CHO recovery, and which will also be key to maintaining low energy use and GHG emissions. In the next nine sections, the key R&D need areas will be highlighted, and expanded on, to describe the perceived need, and suggest what R&D might be undertaken to address the need.

The original intent was to look at medium and long-term R&D needs as separate areas. However, the working groups and workshop participants concluded that too little is known about the current CHOPS process, and its implications, to realistically separate the follow-up technologies based on either time to develop, or specific technology solution areas. The future of R&D in the CHO sector is also hindered by issues of support to R&D, which are considered to be a major barrier to R&D and ultimate application of technology in this sector.

5. Near-Term Technology Needs – Reservoir

Even though conventional heavy oil is responsible for over 25% of Canada's oil production, it would be a mistake to assume that the reservoir process it relies on is well understood. The area that attracted the most attention at the workshop, in terms of participation, was the issue of improving understanding of the reservoir. In the near-term the main challenge is to understand how the existing CHOPS process works and how it could be improved. In the longer term, the lack of understanding of how the CHOPS production has affected the reservoir, is a major hurdle for ultimately deciding on follow-up processes. So R&D on reservoir issues is crucial to the future of oil production in this sector, and in determining what GHG emissions might eventually be expected.

5.1. Understanding Impacts of Production Mechanisms

The CHOPS mechanism is complex as there are numerous factors impacting production. The main areas where additional R&D is needed to improve the industry's understanding of the Cold Heavy Oil Production with Sand (CHOPS) are:

5.1.1. Impacts of Intentionally Producing Sand - The CHOPS process could almost be considered to be a mining method. Many wells have produced over 1000 m^3 of sand during their producing life. From a reservoir perspective, this creates physical reservoir changes that are not encountered in many other conventional oil and gas production situations, which normally only have to deal with changes in fluid and gas properties over time. Properties of the reservoir itself, such as permeability and porosity, are usually constant over time unless some process, such as fracturing is used to generate a step change in permeability. With high rates of sand production, in heavy oil operations, both permeability and porosity are constantly changing throughout the well life, and often in unpredictable ways. This creates significant challenges to reservoir modeling and the ability to predict production. A comment of one workshop participant was that: "we can predict it when it works, but we can't predict when it doesn't". Figures 5.1a and 5.1b show examples of well sand and oil production and attempts to model the behavior

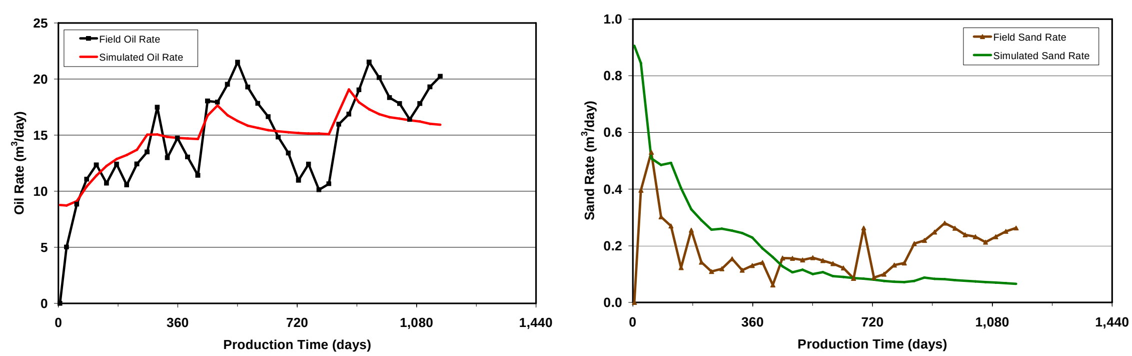


Figure 5.1a (Oil) and b (Sand) – Sample Plots of oil and sand production (From C-FER Presentation at Workshop)

R&D Need A1.1 – Increased study of the reservoir mechanism is necessary to increase the understanding of the CHOPS process, however, this work is dependent on first having better data to work with (see sections 5.2 and 5.3). So even though understanding the reservoir was the highest priority identified, the data collection issues need to be addressed first to enable progress in this area.

5.1.2. Geomechanics in the Reservoir are Important - The produced sand leaves behind it voids in the reservoir, and defining what those voids look like, and how extensive they are is key to evaluating CHOPS production. They are also key to understanding why CHOPS production stops, impacts on well failures, control of the process through operating practices and assessing impacts on potential follow-up production mechanisms. Figure 5.2 shows three potential patterns of sand depletion, which have been proposed. Field data to date is sparse, and relatively inconclusive, and the reality is that actual sand depletion is a complex combination of these patterns, that is affected by reservoir geomechanics, drilling, completion and production practices.

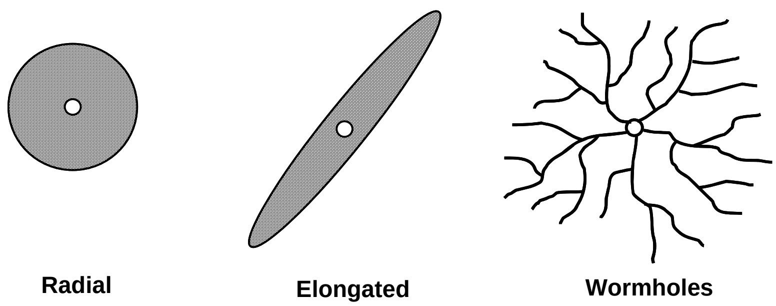


Figure 5.2 – Potential Sand Depletion Patterns (From C-FER Workshop Presentation)

R&D Need A1.2 - The R&D need is to develop consistent evaluation methods, to assess the sand voidage in relation to various key parameters, and allow prediction of sand depletion in diverse CHO operations. Increased understanding should result in operations that can be better controlled, and allow assessment of follow-up recovery methods.

5.1.3. Foamy Oil Production – CHO, produced under cold flow conditions, is produced as foam generated when methane, in solution under reservoir conditions, comes out of solution from the heavy oil and expands. This expansion acts to drive the oil towards the low-pressure production wells, and also radically changes the flow properties of the heavy oil by reducing viscosity. Once foam is no longer produced well production drops off dramatically. Figure 5.3 shows how just one property of the foam, it's volume, changes as the produced oil flows from the higher pressure reservoir into a low pressure well zone.

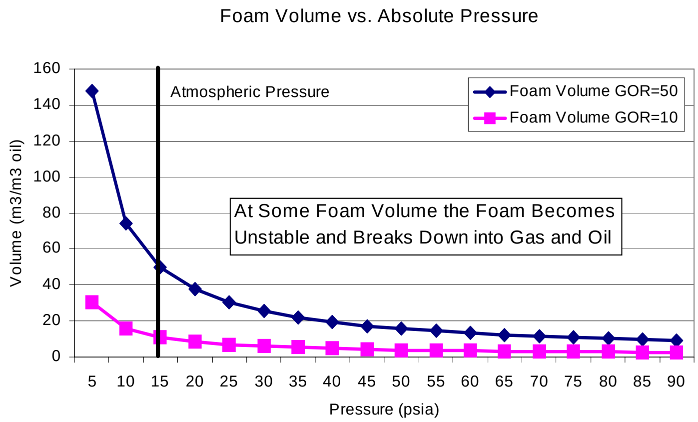


Figure 5.3 – Heavy Oil and Gas Foam Volume vs. Pressure (From New Paradigm Workshop Presentation)

R&D Need A1.3 – Heavy oil foam is difficult to reproduce in the laboratory, potential R&D efforts could focus on downhole pressure measurement, or other techniques to assess foam generation and behaviour in-situ. This would help to determine if there are operating practices and/or other techniques, which could be used to extend foamy production.

5.1.4. Water Influx – Most CHOPS producing wells end their producing life in a flood of water, sometimes after only days or weeks of operation. It is often not known where the water comes from for an individual well before it is abandoned. Options are: a) breakthrough of water from a lower formation; b) collapse of formation top due to sand production; c) water inflow from edges of oil deposit; d) inflow along well casing due to poor completion or loss of seal. Once water rates increase, the CHOPS mechanism can no longer be maintained, and high costs to truck water make continued production uneconomic.

R&D Need A1.4 – Routine testing and finger-printing of potential water sources in a region, and of water produced after breakthrough, to determine the source(s) of the water causing a loss of oil production.

5.2. Improving Data Quality – Sand Cuts

Measurement of various fluids is a key to management of the resource in most oil and gas operations. In CHO, low profitability, lack of a clear link between production data and recovery, and technical challenges related to measurement, have resulted in lower measurement standards in the CHO industry. Oil is relatively well measured as a revenue stream, water is measured as a cost stream, due to impacts on production and disposal. Gas measurement is improving due to the rising value of natural gas and concerns about GHG emissions. However, sand production is poorly measured and recorded, as there is no external demand for these numbers, and in other oil and gas operations sand is of little importance to regulators. With CHOPS, and potential impacts on future recovery mechanisms, the lack of data on sand production volumes is a major concern.

5.2.1. Sand Measurement in the Field – Sand production has been measured by some operators in the past, however, the usual method was either through sand measurement with wellhead fluid sampling, or estimates of solids removed during production tank cleanouts. Neither method of estimation has been studied in great detail, nor are there best practices available to ensure consistent measurement.

R&D Need A1.5 – R&D is required to assess sand quantification methods, and develop a sand quantification standard, specifying how and when to collect sand production information, and how to estimate sand production. The objective is to standardize measurement so that sand production variables, and reservoir performance, can be assessed on a consistent basis.

5.2.2. Reporting of Sand Production – Sand is not a revenue stream, and does not have a major impact on reservoir voidage, so reporting of sand production has not been a priority for government regulators in Alberta or Saskatchewan. CHOPS production is unusual, and does not fit with the standard oil well model on which government reporting and data collection systems are based. The lack of reporting of sand production, in a central database, hinders research on the CHOPS production mechanism, and will also hinder evaluation of potential follow-up processes.

R&D Need A1.6 – A study of potential processes, methods and impacts of adding sand production to the regulatory data collection for CHO, in both provinces, is required to allow a more complete assessment of sand production impacts. While the benefit of this database is diminishing as time passes, it is possible that enough data could be collected to help in the development of methods to estimate historical sand production, based on other measured production performance in similar fields.

5.3. Reservoir Imaging

While estimations of sand production volumes and reporting will help assess CHOPS production impacts, improvements in reservoir imaging methods, to reduce costs, and improve assessment of depleted areas, may be of the most value in assessing potential impacts of CHOPS on follow-up production processes. The reaction of the reservoir, both in recovery, distribution of disturbed and undisturbed reservoir, reservoir flow properties and geomechanics, will have a great impact on the follow-up mechanisms, which may be viable in a given area.

5.3.1. What Should be Monitored? – The first issue is determining what should be monitored. It is uncertain what methods have been tried in post-CHOPS reservoirs, and how those have compared to pre-CHOPS data, or if there are parameters that can provide useful information even when there was no "before" picture. Ideally, imaging methods should show generally where sand and oil production has occurred.

R&D Need A1.7 – An initial effort could be made to collect historical data and imaging results, to determine potential options and potential to learn from multiple methods. The initial assessment could be followed by controlled research, utilizing side-by-side comparisons of imaging methods, in an area with relatively good sand production data, over various periods of time. This type of study may provide insights into determining a preferred method of imaging and analysis. This should continue into the application of a follow-up process, to determine the impacts of the follow-up process based on what occurred under CHOPS alone.

5.3.2. Development of Low Cost Routine Monitoring Methods – Ultimately, reservoir variability is going to drive a need for widespread use of low cost monitoring methods. Given the economic and geographical environment of CHO operations, the ideal monitoring system must be low cost and low impact on agricultural operations. Some type of permanently installed, low cost, passive monitoring system might best meet this objective.

R&D Need A1.8 – New technologies in remote underground, or underwater, sensing and signal interpretation (sonic, microseismic, tiltmeter or other methods), originally developed for military purposes, could be the base technology. Sensing could be combined with new methods for analysis of large relational databases, for potential application in heavy oil fields, equipped with remote real-time data collection links. Source energy could be downhole pumping equipment, signals from formation breakdown, or other sources.

5.4. Near-Term Reservoir Impacts on GHG Emissions

5.4.1. Potential GHG Impacts – Understanding the reservoir mechanism has major impacts on forecasting GHG emissions from this sector. The main impact is in enabling better predictions of how long heavy oil production with CHOPS will persist as the main production method, and, therefore, the current patterns and sources of GHG emissions. The GHG impacts of the current process are becoming better understood, and options can be economically implemented to mitigate the emissions, if CHOPS production is maintained into the future. Figure 5.4 shows the distribution of cumulative Gas/Oil Ratios from 5000 wells in Alberta, drilled since 1995.

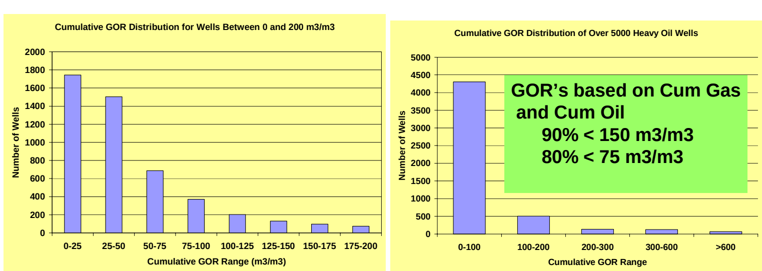


Figure 5.4 – High Level of GOR Frequencies in CHO Wells (From New Paradigm Workshop Presentation)

R&D Need A1.9 – Statistical analysis of existing gas production data and estimates, might better establish a value to use for CHO gas to oil ratios, to allow for prediction of expected gas volumes for CHOPS production.

6. Near-Term Technology Needs – Surface

As indicated earlier in this report, the unique characteristics of this sector result in considerable differences in surface facilities, operating practices and economics, compared to either conventional light oil or oil sands developments. Most of the surface facility issues are not necessarily technological challenges, but are motivational and economic challenges, as solutions exist or have been developed, but there historically has been little incentive to adopt those solutions. Changing economic, environmental and security priorities in the sector now provide a growing motivation for reassessing past practices, and developing improved practices that can be easily implemented in new and/or existing surface facilities.

6.1. Collection and Utilization of Methane – From a GHG perspective, the main target for mitigation is the widespread practice of venting produced methane to the atmosphere. As a GHG methane has 21-23 times the impact of an equivalent mass of carbon dioxide, over a 100-year period, and an even greater impact in shorter timeframes. In the Working Group sessions, this issue was assessed as one where the technical solutions exist, but are either not required by regulation, or not yet sufficiently motivated by positive economics. The gas is produced at low pressure, and relatively low rates, making recovery, treatment and use less attractive than for higher rate solution gas from light oil, or from higher rate gas wells. The produced gas is generally over 95-97% methane, which is a colourless, odourless gas that is lighter than air and quickly dissipates once released. As a result, economic conservation, and GHG related environmental concerns, are the only factors that would drive mitigation of these vents. Figure 6.1 shows that the industry, at least in Alberta, has reduced methane venting (which is mainly from CHO and bitumen operations) by 40% since 2000. This reduction has been driven mainly by increasingly positive economics as gas prices rise, and provincial regulations which require economic conservation, as well as producers becoming more aware of the volumes of gas being vented.

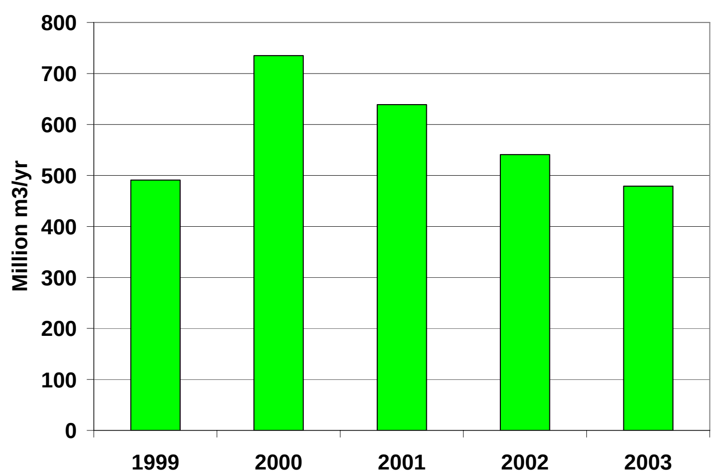


Figure 6.1 – Solution Gas Vented in Alberta
(Source AEUB Venting and Flaring Report ST 2004-60B)

R&D Need B1.1 – The consensus of the working group experts, and generally supported by the larger workshop,[3] is that the main R&D focus is to further develop and clarify the business case and incentives for vent gas conservation and/or conversion. Economic case studies assessing limits of economic gas recovery, and clear rules, guidelines, targets and incentives for GHG reduction are required to stimulate further reductions in methane emissions.

6.2. Transportation – Sand, Water and Heavy Oil – Currently most CHO, along with the associated sand and water, is transported by truck from wells to central batteries or disposal facilities, but other options are possible that require various levels of R&D to economically assess or demonstrate, as well as development of some coordinated approach to effectively implementing them. (see Figure 6.2)

Enhance Trucking Efficiency - Trucking is a high cost, manpower and energy intensive option, on a per barrel of material moved basis, so only remains economic when water production is low. However, the current trucking infrastructure is generally recognized to be inefficient, as it depends on a large number of small, independent owner/operators, under a wide variety of contracts or sub-contract, serving a large number of producers with overlapping operations. Little effort is put into optimizing truck dispatching or haul routes, to minimize haul distances or fuel consumption. Existing technologies such as centralized, GPS-based truck dispatch, combined with remote production monitoring, could generate significant savings in energy use, GHGs, other air emissions, vehicle safety and maintenance or replacement costs. As some trucking is always likely to be required, and steps to improve truck fleet operating efficiency could be immediately implemented, with only modest capital investments.

R&D Need B1.2 – The main need is for a study of the current trucking system in the region by transportation experts from other natural resource sectors (logging, mining), which have already addressed this issue in their operations. Study needs to assess options and implementation methods that would be a win-win for the producers, truckers, operators and local rural residents.

Pipeline Gathering Systems - The main barriers to replacing trucks with pipelines, are the higher capital costs to producers, and the risks associated with moving high viscosity oil and sand in a pipeline, where loss of flow might result in plugged flowlines and lost production. Adding some kind of hydrocarbon diluent, heat or warm water, at the wellsite, can allow the heavy oil to flow, but all involve additional costs and often require some immediate action to be taken by the operator if flow from a well is stopped for even a few days. C-FER Technologies Inc. conducted a Heavy Oil Gathering System (HOGS) study in the late 1990's (see Figure 6.2), that considered a wide variety of pipeline options, and showed that heavy oil gathering in pipelines had potential to be an economically feasible

[3] Use of low pressure vent gas for low pressure burners and small compressors was given a large number of votes in the workshop, but option studies have already been completed that show there are many proven options that provide positive economic payout, but not the short-term payout needed to compete with other corporate opportunities for capital.

alternate to trucking. Since that time Husky, Nexen, and some other producers have been conducting small-scale pipeline tests, to convince themselves that the systems are practical and operable under field conditions. The consensus of the working groups was that gathering with pipelines is now close to being considered technically and operationally proven. As well pipeline gathering systems will likely be required if production is to move past CHOPS, as trucking would not be a viable option for most proposed EOR methods.

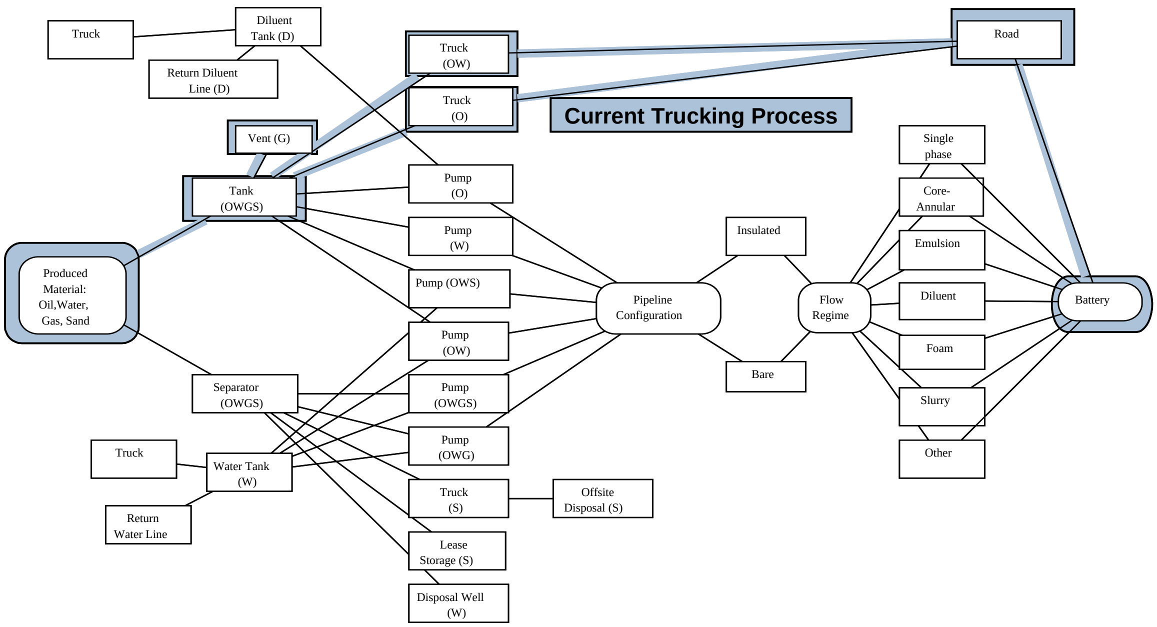


Figure 6.2 – CHO Transportation Options from Well to Battery (Diagram from C-FER Technologies Inc.)

R&D Need B1.3 – The near-term working group consensus was that a detailed economic case needed to be developed to convince producers that pipelines are a feasible heavy oil collection system, and to define the best applications and best practices in implementing the conversion from trucks to pipelines. The case for pipelines could be further enhanced by assessing EOR impacts on trucking.

Sand Separation – Both pipelining and trucking could be enhanced significantly, if the produced sand could be separated or cleaned to an acceptable standard and left on the wellsite, or produced in a dry form that could be used elsewhere. This was ranked highly in the workshop surface facilities break-out group. Husky, and some other operators, have been developing improved sand handling methods, such as single truck systems for tank clean-out and hauling.

R&D Need B1.4 – A study is needed to assess options for dealing with sand right from downhole to ultimate disposal. Some studies by C-FER and others in the past showed promise, but new methods and techniques have evolved since then, making it worthwhile to revisit the options. For disposal on the well lease the main issue is the salt content of the solid waste.

6.3. Fired Equipment Efficiencies – Most of the fuel use, in CHO production, is for lifting the production to surface, using natural gas engines to drive pumps and for on-site lease tank heating. Generally, the split in fuel use will be about 60-80% going to tank heating, and 20-40% going to pump drive engines (See Figure 6.3). Most of the tank heaters used in CHO are very simple, low cost, flame-arrested, emersion fire-tube heaters, based on 1940's technology with extremely simple control, and often no control over excess air. As a result overall heating efficiencies are in the 30-50% range, vs. 80-90% efficiencies that could be achievable with more expensive heating and combustion systems. In many cases vent gas is used for fuel, so net GHG emissions and energy loss is actually reduced, even with low efficiency heaters. Where vent gas is used as fuel there is little concern about heater efficiency, until the surplus vent gas is being recovered and has some potential sales value. Where more expensive fuel is used (e.g. propane @ $20/GJ), operators tend to reduce the lease tank temperature to 60-70 degrees C (vs. 80-95 degrees with vent gas). The tradeoff, with lower tank temperatures, is less water separation and longer truck loading times, due to the increased oil viscosity at lower temperatures.

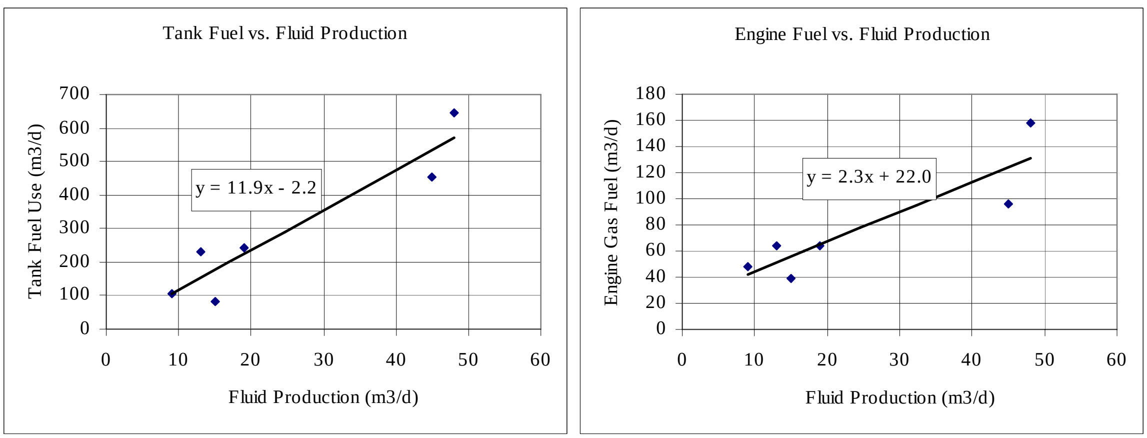


Figure 6.3 – Example of On-lease Fuel Consumption for CHO Wells (New Paradigm CHO Vent Options Study 2000)

R&D Need B1.5 – PTAC is currently managing a $240k project, through it's Technology for Emissions Reduction and Eco-Efficiency (TEREE) committee, to investigate options for significantly increasing the efficiency of all emersion type heaters, in oil and gas operations. The intent is to find low cost methods of increasing efficiency that can be retrofitted into existing systems. Other R&D work to improve efficiency of the overall tank and heater system may still be required.

6.4. Development Planning – Most CHO wells are drilled as single vertical wells, while some operators prefer to directionally drill wells, in 4-7 well clusters or pads. Pad development is an advantage for lowering the costs, and operating issues, associated with energy and GHG reduction opportunities, such as vent gas conservation, pipelining, optimizing trucking, and conserving energy use on-site. The downside factors discouraging pad development are: generally higher capital costs for drilling, potential for increased frequency of well pump failures, and some loss of flexibility in scheduling drilling operations. As the value of energy increases, or regulations controlling venting are brought into effect, the case for pad development increases to allow for greater energy conservation. Pads would also become more economic with any type of EOR process, to optimize use of facilities and minimize surface costs.

R&D Need B1.6 – Operators have divergent views on pad vs. single well development. A collaborative economic assessment to develop a model, which would assess factors favouring pad development vs. single well, as a function of the various capital and operating cost factors, might help to standardize and rationalize development in the region. Such a model would also allow assessment of regulatory, technology or energy price impacts on resource development strategies and options.

7. Near-Term Technology Needs – Drilling, Completion and Production

As with the Reservoir Technology needs (Section 5), a great deal of the technology development in the areas of Drilling, Completions and Production, are driven by the degree of understanding of the oil, sand and water production process. Due to the lack of understanding of the CHOPS process, development of downhole technologies has been limited to independent field trials by various operators in specific fields. Since these technology areas are a key focus of development for all oil and gas operations, there is no shortage of new options to try, what is lacking is a consistent means of deciding what technologies to try and how, where and when to widely apply them in CHO operations. Where a technology proves to be significantly better than past practice, it is often copied by others in that area, and occasionally migrates to other operations. Where a trial has been deemed a failure, or if no significant benefit is observed, it tends to be quickly dropped. In general, CHO producers seem to be willing to try new and novel systems to enhance oil production, but there has traditionally been little coordination, collaboration or in-depth analysis of trials. The main R&D areas identified reflect the uncertainties related to the CHOPS process, and impacts of potential follow-up processes.

7.1. Understanding Water Inflow – The highest priority identified for this area, in the workshops, was to understand water inflow to CHO wells. As discussed earlier, most production stops unexpectedly with a flood of water, sometimes after only a few days or weeks of operation, but the source and mechanism of the inflow is not understood. The usual response is to drill another well, rather than spend potentially more money trying to determine the source and shut-off the water. To date only a few attempts have been made to assess the water source by "fingerprinting" water in adjacent formations. Without understanding the water sources, and inflow mechanisms, it is very difficult to devise a drilling, completions and production strategy or well design to avoid or delay water breakthrough.

R&D Need C1.1 – Collaborative efforts to test and enhance cost effective water shut-off techniques using cement, gels, waxes, sulphur, etc. are needed. Finding out what shut-off techniques work, and under what conditions, may also provide answers to reservoir questions concerning CHOPS and post-CHOPS reservoirs.

7.2. Designing Robust Wells – The second highest concern for drilling and completions, at the workshop, was related to the uncertainty of future recovery methods. The assumption, in the workshop breakout group, was that thermal recovery methods might be the follow-up process, and existing well casing designs are not designed for high temperature operations. High temperature completions require changes in the cement and casing used in the well, and also may require "pre-stressing" of casing to prevent casing failures, which would increase well costs. Other EOR post-CHOPS processes may also negatively impact wells drilled with existing practices. Even if existing wells are abandoned, and not used for follow-up processes, their presence in the formation may affect EOR, or the EOR method may impact abandoned wells, which could cause problems with containment of injected materials. Figure 7.1

illustrates some potential failure modes of well casing, which might be observed in unconsolidated formations, due to sand production or formation movement.

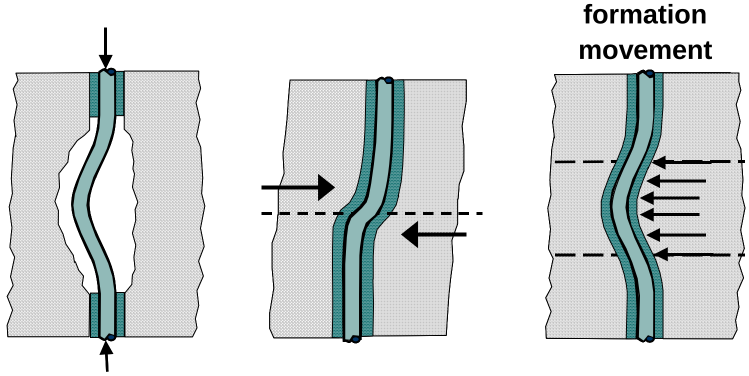


Figure 7.1 – Some Examples of Casing Damage Mechanisms
(C-FER Technologies Inc. Presentation)

R&D Need C1.2 – A collaborative study could be conducted to assess robust well design options and cost impacts, including what may be required for future post-CHOPS development scenarios.

7.3. Controlling Inflow – Due the unusual nature of foamy flow of heavy oil with sand, traditional methods of enabling and controlling flow into a well are rarely effective. The workshop break-out group suggested that more research can be done on slotted well liners, which might control some of the sand while enhancing and prolonging CHOPS production in vertical and horizontal wells. Other options might include the use of near well heating, to improve well inflow at various stages of production.

R&D Need C1.3 – A collaborative study on well inflow options, including near wellbore heating, perforating programs and design of slotted liners could enhance production of CHO wells.

8. Medium to Long-Term Technology Needs – Reservoir

As was stated in earlier sections, the primary barrier in projecting medium and long-term needs for CHO R&D, and associated potential GHG emissions, is the lack of understanding of the CHOPS process. Until better data and answers concerning CHOPS are gathered, the main effort in reservoir R&D should focus on high level, or theoretical, assessments of how the various potential EOR methods might perform, or be adapted to work, in various CHOPS scenarios. C-FER, ARC and others have conducted some geomechanical, well bore and reservoir studies, that tend to indicate the CHOPS mechanisms or theories that best seem to match the available data. These could serve as base case scenarios for work on post-CHOPS, or enhanced CHOPS processes. The surprising result, from the reservoir workshop breakout group, was the lack of support for thermal recovery, based on its high energy intensity, and the expected lower efficiency of thermal processes in thin oil zones.

8.1. Fundamental Work to Extend Low Energy Primary – From an energy intensity point of view, the existing CHOPS based primary production process has some very desirable features, assuming that other issues with surface impacts can be dealt with. Learning how to operate in a way that would extend oil production, and increase average well productivity and reserves capture, would be very desirable for increasing economic recovery. An example is to follow-up on C-FER's work on geomechanical behaviour in CHO reservoirs (see Figure 8.1), to assess methods of controlling or altering the geomecanical stresses to favour increased cold production.

- **Disturbed zone may grow toward lower stress**
- **Adjacent zones tend to attract one another**
- **New wells may be blocked from network by high stresses**
- **Infills may see little depletion**

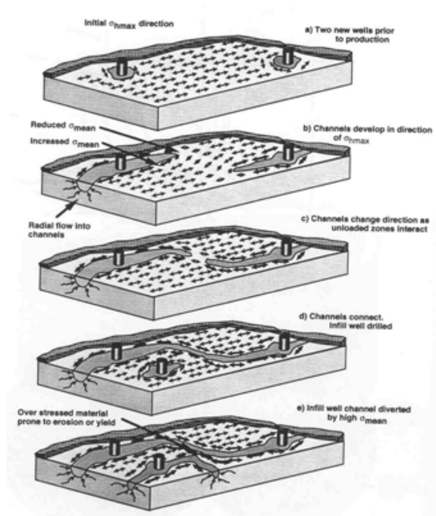


Figure 8.1 – A Potential Reservoir Mechanics Model of Reservoir Depletion (From C-FER Presentation at Workshop)

If variable in-situ stresses are important, then potential methods could be developed to control them, similar to what is done in cyclic steam operations in the Cold Lake region, where in-situ and induced stresses are known to impact the development of steam channels. If there are preferential directional stress patterns, then wells might be drilled in patterns and spacings that take advantage of the stresses, or methods, such as water, inert gas injection or periodic heat treatments could be used to change stress patterns or seal communication paths.

R&D Need A2.1 – A collaborative study is needed, to assess methods of altering formation properties or operating practices, to extend primary production. Factors included might be: assessment of recovery vs. production rates, pumping strategies by different operators, geomechanics modeling and assessing the impacts of various factors on well productivity and reservoir recovery under primary production. Should cover cases for new wells and pool developments, as well as existing pools that have already been fully developed.

8.2. Follow-up Processes – CO_2 – Of the potential follow-up processes, considered by the workshop attendees in the reservoir breakout group, CO_2 injection was considered to be the follow-up process of most potential interest. Due to the presence of large point source emitters of CO_2, it is assumed that concentrated CO_2 will be available at low cost, and that there will be additional economic and environmental benefits for sequestering this GHG as a result of Kyoto commitments. A key aspect of research, for all CO_2 proposals, will be to determine sources and costs for the CO_2. Husky does have a large heavy oil upgrader in Lloydminster, that has a relatively pure waste stream of CO_2 as a byproduct of hydrogen production. Another source option (illustrated in Figure 8.2) may be portable gas generation systems, from combustion of low-pressure vent gas. This would reduce vent gas emissions, while at the same time producing a high volume of N_2/CO_2 at a site, without permanent capital infrastructure and high-pressure CO_2 pipelines.

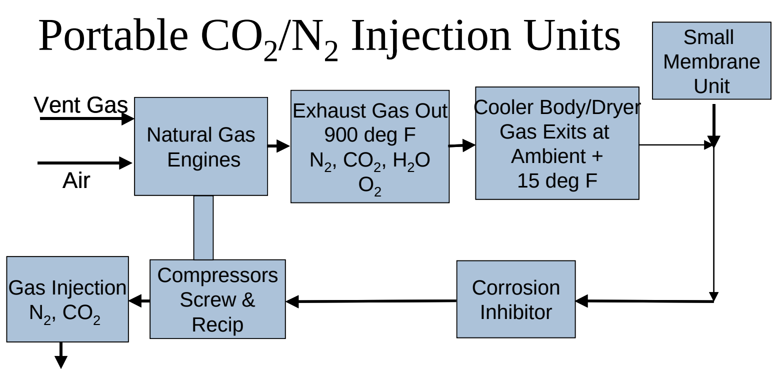


Figure 8.2 – Potential Portable Source of CO2 for CHO EOR (Source: New Paradigm)

R&D Need A2.2 – Assess the availability and costs associated with various means of delivering CO_2, or CO_2 containing source streams, to pools in the Lloydminster region. As with other CO_2 injection processes, other factors, such as ultimate CO_2 sequestration, would need to be assessed, based on post-CHOPS scenarios.

8.3. Follow-up Processes – Solvents – The second most favoured process, after CO_2, is the use of solvent based processes, such as Vapour Extraction (VAPEX), to dilute the heavy oil in-situ and allow it to flow to producing wells. It is assumed that solvent processes will be less energy and emissions intensive than thermal heavy oil processes. As with CO_2, a primary driver will be the cost and availability of solvents, and the ability to recycle solvent. There are few gas plants in the Lloydminster region, so solvent might be supplied from the Lloydminster upgrader. Due to the light/heavy differential, solvent processes may be at a disadvantage compared to similar applications in oil sands, where royalty agreements may help to reduce the impact of buying solvent at light oil prices.

R&D Need A2.3 – Assess the availability and costs associated with various means of delivering and recycling solvent for pools in the Lloydminster region, as well as reservoir and other factors, such as solvent losses, based on potential post-CHOPS scenarios.

8.4. Follow-up Processes – Air Injection – In the past air injection was also described as a fire-flood, as the intent of the process is to use light hydrocarbons, CO_2 and water vapour, produced by combustion of heavier heavy oil components in the reservoir, to push and displace heavy oil to production wells. The main constraints on air injection, are the costs of air compression and controlling the injection and combustion in the reservoir.

R&D Need A2.4 – Assess the availability and costs associated with vent gas fueled portable air injection, as well as reservoir and other factors, such as retention of combustion products in the reservoir, and potential recoveries, based on potential post-CHOPS scenarios.

8.5. Follow-up Processes – Waterfloods and Chemicals – The only other potential follow-up process, supported by the workshop breakout groups, was related to various forms of waterflood in conjunction with heat or chemicals, such as polymers and surfactants to improve performance. Hot waterfloods have been suggested as a low cost option, which would utilize produced water with minimal treatment and vent gas as fuel. Some waterfloods have been tried in various locations with mixed results, but additional knowledge might be gained by more in-depth analysis of these pilots.

R&D Need A2.5 – Assess the availability and costs associated with various means of delivering water and chemicals to pools in the Lloydminster region, as well as reservoir and other factors that would impact potential post-CHOPS scenarios.

9. Medium to Long-Term Technology Needs – Surface

Many of the most critical surface technology needs will likely be addressed, in the near term, by dealing with issues such as venting, trucking and sand. In the post-CHOPS period, surface facility needs will be highly dependent on what process, or processes, are determined to be appropriate in post-CHOPS reservoirs. The surface facilities break-out group assumed that either water-based floods, or steam injection, would be key follow-up processes. Part of this assumption was due to input information to the workshop, that migration of thermal recovery might be the medium term solution, and the existence of successful thermal operations in CHO operating areas, which were not initially produced with CHOPS. While thermal or water methods may not be the main processes considered for recovery, there will still be water produced, and a need to manage water and land-use issues in the region. For the most part, the surface facility issues covered in this section, are shared with other oil and gas sectors as indicated in the subsections.

9.1. Regional Water Management – With CHOPS and trucking operations, water management focuses mainly on trucking water and water/sand mixtures, and the energy costs of water disposal systems, that are the largest users of purchased electrical power in the CHO sector. Wells are often quickly shutdown if produced water rates get above 2-3 m^3 water per m^3 of oil, as producing, heating, trucking and disposing of water is more expensive per m^3 than handling the produced oil, and water contributes nothing to revenues. The water volumes managed, in the current situation, are much smaller than they would be with pipelines, or any post-CHOPS water-based system, that would make it possible and desirable to operate at higher water to oil ratios (WORs). If thermal steam processes are proposed, then a regional water supply pipeline system may be required, with the water coming from surface waters (now being discouraged in Alberta) or subsurface saline aquifers. Most of these water management issues are the same as those faced in conventional light oil operations throughout the Western Canada Sedimentary Basin (WCSB).

R&D Need B2.1 – Assuming trucking of water is almost eliminated, the next phase of technology development needs to look at handling water and water recycle more cost effectively. An industry study on options for lowering water management costs, and accessing saline water zones, would help producers and regulators develop an effective water and energy management strategy.

9.2. Water Treatment and Purification – Water treatment can be required at a number of stages in a thermal or water-based EOR process. This issue is a growing concern in the oil sands areas, where winter water availability from the Athabasca river is a concern, and producers are being challenged to reuse produced water for steam generation to minimize water inputs and outputs. Much of this technology development and assessment is actively underway, for oil sands projects, and will likely be renewed for conventional light oil operations seeking to substitute saline water to reduce fresh water use.

R&D Need B2.2 – A basic need for water management is to identify potential water sources, assess the quality of the water available, and locate suitable disposal zones for any surplus water in the Lloydminster region. As part of a larger effort for the on-going production of conventional light oil, work should also be undertaken to develop options to reduce the energy required for water management and disposal.

9.3. Surface Development – Flexibility and Footprints – As the long term plan for further development of CHO, post-CHOPS, is unclear, there is a need for work to begin on considering how future recovery scenarios might be developed. With 85-95% of the resource remaining in the reservoirs, the expectation should be that some future efforts will be made to recover this oil. Also, as most of the conventional heavy oil production is in agricultural areas, future developments should be planned so as to minimize the footprint on both land, air and water resources in the region. EOR projects in conventional light oil are often managed by "unitization" or "joint ventures", where common facilities are shared and the area is logically developed for the benefit of all stakeholders.

R&D Need B2.3 – Provincial regulators should be looking ahead to what might be needed for future CHO developments, and begin looking at land, water and air issues to allow them to better implement regulations, and guidelines, to deal with issues before they become problems. Public concerns with oil and gas development will increasingly require more advanced planning, public education and input to avoid conflicts, which can adversely affect development of the resource.

10. Medium to Long-Term Technology Needs – Drilling, Completion and Production

As with surface facilities, the medium and long-term needs for drilling, completion and production technologies are all dependent on what the follow-up process(es) might be. In the past, drilling technology development focused on drilling faster and cheaper, as CHOPS wells were sometimes treated as “disposable assets”, in that they might water out right away and a new well would have to be drilled. Completions and production equipment also focuses on low cost, low maintenance and highly portable facilities to cope with problems such as foam and sand production, loss of production and sudden changes in well productivity. In the medium to long term, any follow-up process will be more complicated than CHOPS, and will require greater investments in wells, pipelines and leases, so preserving well productivity will become a major driver.

10.1. Tools for Flexible, Controlled Drilling – The assumption by the workshop drilling breakout group, was that for post-CHOPS drilling “everything gets worse”. Drilling into partially depleted, unconsolidated reservoirs, that may contain unexpected high permeability channels, or inter-zone communication paths, may result in loss of drilling muds and fluids to producing wells, loss of casing cement integrity, and wellbore collapse while drilling. These are already problems in some areas, and will be made worse if future wells need to be directionally drilled or horizontal wells.

> **R&D Need C2.1** – Need tools to allow drillers to avoid disturbed zones, so that wells are placed to achieve optimum recovery, while avoiding drilling problems. Tools such as 4-D seismic, and measurement while drilling (MWD), generally exist now, but need to be applied and verified for use in accurately detecting disturbed zones. Research might consist of field trials to intentionally drill in mature areas, to establish the types and severity of problems that may be encountered, and to assess diagnostic and control tools.

10.2. Inflow Enhancement – Near Well and Wellbore – Well completion methods could have an impact on enhanced CHOPS, or post-CHOPS, production rates and ultimate reserves recovery. As with drilling these issues will become more complex in disturbed zones, and in attempting to use any existing wells that have already been producing. e.g. can you recomplete a well after it has produced 1000 m3 of sand? How can inflow rates be increased without accelerating water production?

> **R&D Need C2.2** – Many completion methods and techniques have been tried by CHO operations, however, few cases exist where there has been proper controls and analysis of results, to allow any firm conclusions to be drawn. R&D to gather information on potential completion options, including gathering information on past field trials, may help to identify “hidden successes” or technologies with the most promise for future development.

10.3. Adapting to Potential Recovery Methods – The lack of future reservoir development and recovery scenarios, significantly hinders R&D in the areas of drilling, completions and production. A significant concern, already expressing as a near-term need of developing a robust well design, is that current well drilling and completion practices may become obstacles to future oil recovery, and that the existing investments in wells and lifting equipment might be wasted, or require significant reconditioning, to serve a new recovery process. Potential impacts of post-CHOPS recovery methods vary widely depending on the ultimate processes adopted. Key drilling questions are related to well configuration (vertical, horizontal or "spider" multibore wells), thermal vs. non-thermal casing design, and the ability to control drilling in disturbed zones vs. undisturbed. Completions issues include well perforating methods, potential corrosion and erosion of well tubulars, and control of water and oil inflow. Production issues will focus on downhole measurement methods and pumping systems.

R&D Need C2.3 – The collaborative study suggested in R&D Need C1.2 could be done in parallel with similar studies to assess well completion and production options, and cost impacts, to assess what technology may be required for future post-CHOPS development scenarios.

11. R&D Process and Support Needs – Reservoir

As a second session of the March 21 workshop, the three breakout groups were asked to discuss R&D needs from the point of view of systemic barriers to technology development and deployment, in the CHO sector. With a patchwork of CHO lease ownership, and minimum cost development on a well-by-well basis, there is little incentive for collaboration or investment in R&D, for the current operations skimming the first 5-15% of the resource. Production is generally managed by drilling wells faster than they dry up or water out. Little time, tools or interest is shown for analysis of individual well or pool performance over time.

11.1. Need for Data to Allow Simulation – The analysis of actual and potential reservoir performance for CHO, is more complicated than for conventional light oil reservoirs, where gas volumes are routinely measured and sand production is minimal. In conventional oil fields, all the basic data needed for simulation is reported through the provincial regulators, with clear standards of measurement for the revenue streams of gas and oil and the water disposal stream. Currently two models are used to predict CHO performance, as indicated in Figure 11.1. A major problem with widespread use and adoption of these linked models, is the lack of actual data to input to them.

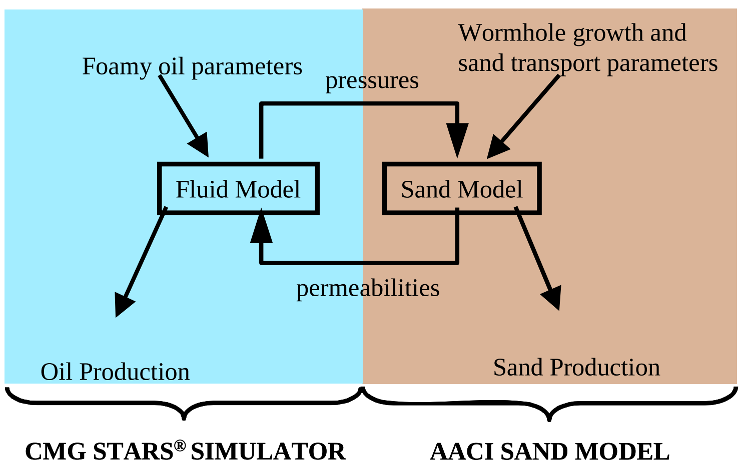


Figure 11.1 – Linking of Reservoir Models for Fluid and Sand (From C-FER Workshop Presentation)

For the Fluid Model, a significant input is the foamy oil parameters, which are dependent on field measurement of gas to oil ratios, and downhole pressure conditions. Until recently there was little measurement of gas production, as most of it was being vented, and a recent vent quantification study has indicated that historical gas volume estimate errors may be –100% to +100-300% of actual, in some wells or pools. As gas volume estimation methods vary, there are also biases between companies in the same pool or province, as a result of non-standard measurement, estimation and reporting practices. Foamy flow is also impacted by the size of foam bubbles and pressure effects, that are difficult to replicate in the lab, and very difficult or currently impossible to measure in the field. In the sand model, data on sand production rates is needed, yet this data is not a requirement for regulatory reporting, so there is little quality data being collected on produced sand volumes, and even less reported.

R&D Need A3.1 – Some collaborative process is needed to develop and implement standards, and systems, to begin collecting “good enough” gas and sand production data, for either a number of selected new fields, or, better yet, for the entire CHO industry. This would allow researchers to more fully test and validate fluid and sand production models, and allow producers to consider use of models for prediction or to identify where more work is needed.

11.2. Cost Effective Quality Reservoir Data Collection – As well as the basic volume data needs discussed in 11.1, there is also a need to develop new cost effective methods of characterizing and tracking any changes in the reservoirs over time. The data collection can be split into increased and better use of proven methods, such as pressure testing, tracers, geology and imaging, and “things we don’t know how to measure” like wormhole dimensions, and determining where water is coming from through oil and water (and solids?) fingerprinting.

R&D Need A3.2 – Collaborative effort is needed to list, prioritize, design and field-test methodologies for in-situ determination of reservoir characteristics.

11.3. Coupled Geomechanics and Reservoir Simulation – In addition to modeling of fluid and sand production, there is also a need to further couple these models with geomechanics, to better study the growth and distribution of disturbed zones in the reservoir over time. Such a model would allow investigation of alternative operating strategies, and the on-going production or redistribution of solids in the heavy oil reservoirs, as operations move into post-CHOP recovery processes.

R&D Needs A3.3 – Collaborative work is needed to expand modeling of geomechanical behaviour of shallow heavy oil deposits, and to integrate these models with the fluid and sand production models.

11.4. Collaborative Data Analysis – With the low value of heavy oil production, there is little incentive for any single producer to spend a lot of time or money on data collection and analysis, that will ultimately benefit all producers. Also, much of the CHO testing data is unique, so not suitable for government reporting systems. C-FER Technologies already has established a number of long-term, international RIFTS (Reliability Information and Failure Tracking Systems) projects for Electric Submersible Pumps, Progressing Cavity Pumps and Sand Control Completions, that could be a model for service providers collecting and analyzing key CHO data, such as 4D seismic, completion methods, water fingerprinting, sand production, etc., on an industry wide basis. After an initial phase of determining data needs, and submission and analysis methods, the data collection can become routine, and gradually build into a valuable data base, that can be analyzed to develop best practices, gain insights and test new theories.

R&D Needs A3.4 – Proposals should be sought for collaborative data gathering and analysis efforts, for key issues such as sand production, water fingerprinting, 4D seismic results, etc., to begin centralized collection and analysis of data by appropriate experts on an industry-wide basis. Consideration should be given to the ability to merge data, from various existing CHO databases, such as C-FER's PCP and SCC RIFTS Projects, and regulator production and geologic databases, for consolidated analysis and technology dissemination.

11.5. Field Pilots – Some piloting of post-CHOPS processes have taken place (waterfloods, steam and chemical), and other pilots (VAPEX) have been discussed. As with other data collection and analysis, the industry has not been able to economically justify many pilots by individual producers, and, those that have been done, often suffer as any extra costs needed for research goals may not be provided. As with data analysis, wider use of collaborative pilots, where one or more producers build and operate a pilot, while others contribute funds to enhance measurement, monitoring, diagnostics and expert analysis would help ensure that all benefit from what is learned. This also allows for consideration of a full set of data to be collected, including parallel testing of analysis tools and methods, which would never be considered by a single producer in a competitive, commercial pilot operation. This would leverage government supplied R&D funds by avoiding multiple, ineffective and/or poorly monitored pilots, by many producers, to test a single process.

R&D Need A3.5 – Development of a funding and execution model to promote more extensive collaboration, and data sharing, to generate higher quality, and higher value results from field pilots.

12. R&D Process and Support Needs – Surface

The R&D process, and support needs, for surface technologies are different in most ways from the Reservoir needs. Most surface technologies will be based on tools, equipment and processes, which have already been developed for other oil, gas, transportation or industrial sectors. They must be low cost (mass produced), low risk (widely used elsewhere) and simple, and, as a result, aren't likely to evolve from new fundamental institutional research (See Figure 12.1). Data on surface operations is more readily available, so the challenge for the R&D process is to find the most suitable technology on the market, and adapt it, if necessary, to CHO applications. In this process, the surface workshop group stressed that, large vendors, SME's and individuals should be doing the R&D, not universities or institutions. What is generally lacking is support from producers, to assess and demonstrate technologies, and economic motivation for producers, to buy improved equipment.

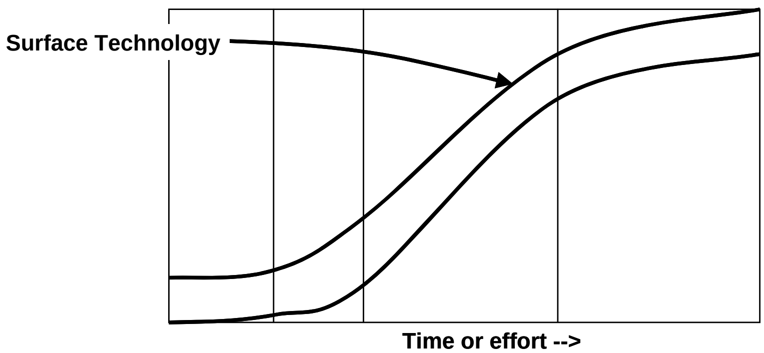


Figure 12.1 – Surface Technology on the Development Curve

12.1. Definition of Problems – A major problem, for most vendors and SME's, in attempting to develop products for the CHO sector, and oil and gas in general, is that often there is little definition of the problem to be solved, or what would be considered a successful result. Generally producers advocate that others do R&D for them, but don't provide enough basic information on rates, temperatures, pressures, compositions, economics hurdles, etc. to allow reasonable design. Small vendors, in the heavy oil region, who are willing and able to go out and gather input data themselves, often develop the best solutions, and better understand the market conditions. Defining success is a problem as vendors, or innovators, may have solutions that seem to them to be economically attractive, and technically solve a problem, but the solution does not meet oil producer hurdle rates for investment. e.g. vendors may design and price a vent gas solution, based on a 3-year payout using commercial gas prices, whereas the producers define success as 6-month payout using a much lower value assigned to the gas.

R&D Need B3.1 – Producers should collaborate through organizations, such as PTAC, to better define their needs and success criteria, and communicate those to a broader range of vendors and other stakeholders, not as a request for research proposals, but as an information bulletin. If a product meets the criteria, producers should be willing to buy it. If no products are proposed, that can meet the success criteria, then producers should review the need and either adjust the criteria, or issue a request for research proposals. See Figure 12.2.

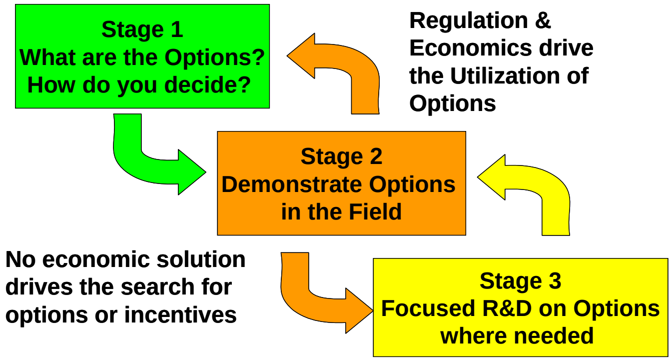


Figure 12.2 – Process for Adapting and Adopting CHO Surface Technology (From New Paradigm Workshop Presentation)

12.2. Assessment of Technologies in the Field – As with other Canadian research efforts, there is often a considerable gap between R&D, or even new products, and commercial sales into the CHO industry. As most surface technologies may require adaptation, to meet the specific needs of CHO operations, field assessments are a key requirement for commercial sales into the market. Currently this process is adhoc, and vendors may have to fund demonstrations for a large number of producers, before they get a single sale, and yet also must deal with the producer's aversion to exclusive suppliers, and expectations of rapid (6 month payout) economic returns on investment. The expectation of most CHO producers, is that vendors will absorb capital costs of equipment field trials, but producers also rarely provide technical support to the design, data collection and analysis of trials, which some vendors also may not be able to do, so results are often inconclusive.

R&D Need B3.2 – A collaborative model for field-testing, using agreed to third parties to assist with a smaller number of well designed tests, with improved data collection and analysis, potentially could result in lower costs and more rapid deployment of cost saving technologies. Funding of the third party contributions might be shared between producers, vendors and government sources, as all stakeholders will benefit from a higher quality and impartial assessment.

12.3. Support for Local SME and Industry Supplier R&D – As industry funding support for CHO technology, especially where there are lower economic prizes or enforced regulation, will be minimal, there is a need to find and implement new funding mechanisms. Vendors are mainly marketing commodity products, in a very competitive market, with tight margins, so have little cash flow to allocate towards new product development, or patenting or protecting new products from infringement once they are developed.

R&D Need B3.3 – Assessment of enhanced and simplified SR&ED credits, greater and easier (single window) access to IRAP and other federal or provincial funding that are more focused on technology development than job creation.

13. R&D Process and Support Needs – Drilling, Completions and Production

Generally, there was little indication of a need for lab testing in this area, unless a specific need, or a generic variable, is identified that can be realistically simulated in the lab before a field pilot. Most of the work will be in the field, through equipment trials or piloting. As in the case of surface equipment, most of the development work is performed by equipment vendors, to meet producer needs, however, many trials are also initiated by producer champions, who see an interesting technology and want to try it out in their field. Drilling, completions and production trials and pilots are similar to surface trails, in that usually neither the producer nor the vendor has the time or funding to properly plan and execute a controlled field trial, so “trial and error” prevails. Traditionally, equipment trials and pilots have had poor monitoring and data analysis, and were limited to a subjective judgment of success as being “Yes” or “No”, rather than leading to answers to questions such as “Why” or “Why Not”.

13.1. Field Trials - Trials need to be based on math, logic, design, analysis, data and experiments, a comment made in the workshop was that “often pilots are conducted with none of the above.” Many trials suffer from a poor focus on variable control, little measurement, poor quality data, little interpretation of results, or use of the scientific method to challenge and verify results. At times, trials or demonstrations are not conducted in the right application, yet suppliers feel forced to go along with using a tool in the wrong application to maintain their business relationships with the producers. Often trials, once started, are neglected, due to a focus on production operations over R&D. Successful trials take a patient team effort, with management support for innovative pioneers, so they can obtain the necessary team buy-in, and recognition of successes or “successful failures”.

R&D Need C3.1 – Where there is a problem or opportunity identified in an operation, managers need to be made accountable for addressing the issue and effectively resourcing the development of new solutions, or options, where needed. e.g. Early loss of wells is an on-going chronic problem whose costs should be tracked and used to justify R&D to investigate and attempt to solve the problem. Research should be undertaken to develop a set of key indicators, and benchmarks, for CHO operational performance, that might be later implemented as a Best Practice.

13.2. Shared Funding and Data Sharing #1 – As in the case of surface facilities, CHO producers really can’t afford to conduct quality R&D on their own on a particular issue, but if no one does it than all stakeholders (producer, governments and vendors), continue to lose out on potential benefits. Incentives and funding methods vary by who is funding the work: producers can use royalty breaks, vendors need tax breaks or easier to access SR&ED credits.

R&D Need C3.2 – Shared Funding – Some mechanism is needed to share funding of R&D costs to increase the quality of the work. The workshop breakout group identified that the funding method might vary with the problem: i) Joint Industry Projects (JIP’s) if there are no competing interests between participants (producers, owners of the I.P. and vendors); ii) Unitizing CHO leases for R&D

where companies partner for results, and have some basis for sharing costs and benefits; iii) Regulated R&D (often bad for small producers) could be targeted for a specific problem on shared properties.

R&D Need C3.3 – Data Sharing - While all work and responsibility for obtaining funding, data gathering and testing, cannot be outsourced to a third party, much of it can be. Projects, similar to the C-FERS RIFTS projects, could be implemented with third party researchers who can provide continuity in planning, data gathering, analysis and communication of results.

13.3. Implementation to Realize Benefits – An additional key area for all CHO R&D, is in addressing barriers to implementing technologies to achieve the desired benefits. Issues for CHO are very similar to those covered in PTAC's "Barriers to the Deployment of Environmental Technologies", as CHO technologies, like those for environmental issues, tend to be low margin and low market pull. Large vendors are generally only interested in R&D that might have significant international and sales potential, and where they can control the I.P. to limit competition until they have recovered their R&D investment. Producers want immediately available, proven, low cost, and simple solutions. available from multiple suppliers, without having to invest much in R&D themselves. As a result, the R&D and implementation must be through small vendors, going for a niche market, with low overhead burden, and an ability to move quickly into the field, preferably with some I.P. to limit competitors. So the challenge is how to support R&D by small vendors.

R&D Need C3.4 – A new funding model is needed for supporting the CHO R&D sector. The Alberta Royalty Incentive program does not work well for small projects, as producers are the gatekeepers, and the process is targeted to larger projects, and longer duration research, than is usually needed for CHO. The Gas Technology Institute (GTI) might be used as a potential alternate model. Funds are collected by a regulator, as a royalty based on production levels, and then directed to capable technology or R&D suppliers, who then approach producers for additional support for specific projects. A key factor for implementation is to ensure that the initiator of the technology development, either the producer or a regulator, takes responsibility for ensuring that implementation occurs when a suitable solution is developed.

14. Main Priorities for Technical R&D

In total, this report has identified 41 R&D needs for the Conventional Heavy Oil industry. The main objective is to identify R&D needs for GHG reduction, which is important for federal Kyoto commitments, and potential impacts on global warming. However, it was also an opportunity to identify R&D needs to enhance the relative sustainability of the CHO industry for the benefit of local and provincial stakeholders.

Prioritizing the R&D needs is difficult, as there are many criteria on which the priorities could be based, and the project budget did not allow for a broad-based and detailed review of the needs with knowledgeable stakeholders. In the working group sessions and workshops, however, there was an opportunity to try and gage general relationships and potential impacts. From this the author has attempted to roughly prioritize the R&D needs, towards meeting some assumed criteria for GHG emissions and sustainability goals. From the criteria an attempt has been made to generate a combined listing, which attempts to balance the two objectives of GHG reduction, and sustainability. A summary listing of the R&D needs, descriptions of the criteria, and rating scales used to rank the potential R&D activities, is provided in Appendix B.

14.1. Priorities for GHG Reduction Potential

Prioritization criteria were:

1. **Timing** – R&D activities, which could potentially result in a reduction in GHG emissions, especially methane, before 2008 were assumed to be preferred.
2. **GHG Impact** – Based on current carbon intensities (including venting and trucking) the relative size of the reduction per bbl of production was the main criteria.
3. **Forecasting** – Managing GHG emissions, and the federal Kyoto commitment, require that forecasts of emissions be reliable, so that appropriate actions can be taken to respond. R&D that would allow better GHG forecasts are preferred.

For GHG reduction the **top five priorities** ranked by the author are:

1. **B1.1 Collection and Utilization of Methane** – As methane is the largest GHG emission from this sector, and also has an economic value, it has the largest potential in all three criteria areas. Mitigation technologies exist and are being applied, the reductions to date have been substantial, and can still be significantly improved on. Reducing these emissions will reduce a large variable in future forecasts.
2. **A1.4 Water Influx** – Currently water influx is usually the direct cause of wells being shut-in, and will therefore be the primary factor forcing a change to some other type of recovery, which will increase energy intensity for CHO production. Understanding the mechanisms and causes of water influx, will set the limits on current CHOPS production and determine what follow-up processes will work.

3. **A2.1 Extend Low Energy Primary Recovery** – This is similar to water influx, in that it impacts the time of a potential change in recovery process, that will result in an increase in direct use of energy and other resources.
4. **B1.5 Fired Equipment Efficiencies** – It is known that fired tank heaters consume large volumes of fuel, and are very inefficient, both in combustion and heat transfer. Improvements in fired heaters would reduce emissions of both methane and carbon dioxide, which are currently only roughly estimated, so difficult to predict.
5. **B1.2 Transportation – Enhance Trucking Efficiency** – While the ultimate solution for transportation is conversion to pipelines, this is not likely to happen by 2008, or be retrofitted to many existing wells. As a result, the best way, in the near to medium term, to reduce transportation emissions is to reduce the kilometers driven, and optimize existing trucking operations with existing technologies.

14.2. Priorities Based on Sustainability Criteria

Prioritization criteria were:

- **Economic** – Relative net economic value to stakeholders directly impacted by the on-going operation of this sector. Higher and rapid returns on capital, and long term present value of a technology, at times conflict in this assessment, so present value was generally used as being the most relevant to the provinces, who are the primary owner of the resource.
- **Environment** – Relative impacts on reducing non-GHG impacts on land, water, air and ecologies in the region. These tend to have a greater, and more controllable, impact than GHG emissions do, and have the greatest impact on provincial regulations that govern the industry.
- **Security** – Relative positive impacts on health and well-being of local communities, for such things as employment, sources of funding for services, and long term effective use of resources.

For Sustainability criteria the **top five priorities** ranked by the author are:

1. **A1.1 Impacts of Intentionally Producing Sand** – From feedback, discussions with experts and through the workshop, the largest unknown that needs to be addressed is the impact that large volumes of sand production will have on ultimate recovery and future processes. This factor dictates the longevity, and ultimate recovery, of CHOPS, what the follow-up processes will look like, and what additional recovery they might achieve.
2. **A1.4 Water Influx** – Water influx is high in both categories, as it is potentially a prime indicator of what is happening in the reservoir, and also an indicator of success or failure in the pursuit of long-term low energy (and GHG emission) recovery. The early failures, by water breakthrough, of many CHO wells might be a key parameter in understanding the long-term sustainability of CHO production.

3. **B1.3 Transportation – Pipeline Gathering Systems** – The high cost of truck transportation, and inherent limitations in handling production from potential follow-up processes (e.g. CO2, solvent, water or combustion products), will force the sector to move to pipeline gathering systems at some point, and has the highest environmental impacts to the local communities
4. **A1.2 Geomechanics in the Reservoir** – In developing a better understanding of sand production on the reservoirs, more is needed than just being able to forecast liquid and sand volumes. Geomechanics appears to be the key area where progress must be made, to understand what CHOPS is doing to the reservoir, just as it is key in cyclic steam operations in the oil sands.
5. **A1.8 Low Cost Routine Monitoring** – Understanding of reservoir behaviour requires data, even in an industry with low relative value production. More profitable oil and gas sectors can utilize more sophisticated monitoring, CHO must work towards finding simple, and low cost, methods of doing the same things.

14.3. Merging Priorities

To merge GHG and Sustainability Criteria, and obtain a more robust list of R&D needs, the scores from GHG and Sustainability evaluations were simply added together, and a new ranking generated. This listing tends to focus on R&D needs that will meet criteria in both areas, so will likely best meet more of the needs of all stakeholders. Table 15.1 in the following section shows all R&D needs sorted by the overall priority.

The overall **top five priorities** ranked by the author are:

1. **B1.1 Collection and Utilization of Methane** – With rising natural gas prices, and industry being forced to look at marginal gas resources like coal bed methane or hydrates, it makes little sense to continue to vent gas that can be conserved at a reasonable economic return. The fact that these emissions are also a major source of GHGs, increases the incentive to move ahead quickly to significantly reduce these emissions.
2. **A1.4 Water Influx** – As indicated earlier, this is potentially a key indicator of the sectors future that will likely lead to greater insights in many of the identified R&D areas, and allow for a rational and efficient development of the CHO resources.
3. **B1.3 Transportation – Pipeline Gathering Systems** – In the medium to long term, this is a necessary change for the industry to allow continued production, as more complex processes and methods are implemented.
4. **A1.1 Impacts of Intentionally Producing Sand** – Sand production is the root cause of most of the future uncertainty for the sector, and makes it all but impossible to predict the future of production from this resource. This issue ultimately impacts GHG emissions, as intensity changes with the processes used, and the total emissions also vary with how much of the resource is recovered.

5. **A2.1 Extend Low Energy Primary Recovery** – The best combined result, would be to develop ways to extend primary production as long as possible, to minimize energy and capital inputs, while maximizing recovery. The fact that conventional heavy oil is producible at relatively high rates, with an unusual production mechanism, like CHOPS, means that there may be more novel options out there, if sufficient understanding of the process can be gained and widely shared.

15. Conclusions and Recommendations

Originally, this study was intended to cover a broader scope, which would have allowed further reviews with experts, build more detail and support for the priorities, and generally dig deeper into the R&D issues in this sector. While conventional heavy oil is not as lucrative to producers, as light oil and oil sands are, it does contribute 25% of the WCSB production, is potentially a very low energy and GHG intensity source of oil production, and makes a significant contribution to the local economy, and as Saskatchewan's equivalent of the oil sands. This report has attempted to highlight key R&D needs, to enhance the sustainability of the sector, and reduce GHG emissions, from current and potential future operations.

15.1. GHG Technology Focused R&D

The three main R&D areas, which have potential to have the most impact on GHG emissions, focus on reduction of methane venting, improved efficiency of transportation of production, and improving the efficiency of fuel use in operations. Significant near-term gains can be made in these areas, and the main hurdle is not technical, it is motivational. Efforts in this area must focus on giving producers a reason, and/or incentive, to put changes in these areas higher on their list of investment priorities. The Federal Green Plan may have an impact, however, change is more likely to occur through changes to provincial regulations and guidelines, under current mandates, to ensure energy resource conservation and responsible operation. Finding a win-win mechanism to develop and implement these changes, on both sides of the Alta/Sask border, should not be a major challenge if all parties focus on better use of what is already known, and available to them.

15.2. Sustainability Technology Focused R&D

The main sustainability R&D needs focus on efficient resource recovery, and tackling some major unknowns related to the existing production. As responsibility for the resources ultimately lies with the provincial governments, increasing efforts to understand the potential impacts and implications of current operations on future recovery, should reside with the regulators, and policy makers, in Alberta and Saskatchewan. The fact is that currently there is no way to forecast the future of this sector, so any opinion is equally valid until it is supported by data, understanding and verification through scientific investigation. While the CHO sector is at an economic disadvantage, due to oil price differentials and royalty incentives, logically it should be a resource that is not abandoned after only recovering 5-15% of a resource that most other provinces, and countries, would see as an extremely valuable asset.

15.3. Supporting R&D Efforts

Most of the R&D needs identified in this study are not well supported by current funding programs, or incentives, as the development must be low cost, and systemic changes are needed, to encourage the collaborative and focused efforts required to achieve results. The major issues relate to determining the future of the CHO sector, and the key to the future is in understanding the current production process.

Very little is known, and very little data and knowledge is available, to support R&D efforts, due to the fragmentation of the sector, low economic returns relative to other resource opportunities, and the near-term focus of most producer shareholders. There are opportunities for significant gains, in both GHG reductions, and increased resource recovery, if the systemic barriers can be overcome.

15.4. Transferring Technology to Widespread Use

Once the systemic barriers to research have been overcome, there still remain the barriers to transferring any knowledge, or technology developed, into widespread use. The poor economics of conventional heavy oil production, as a result of discounted prices for heavy oil, few royalty breaks for production and the current low tech basis of operations, build an financial environment that is drastically out of step with other oil, gas and oil sands sectors in the same region. The economic disadvantages, make CHO the sector least likely to attract funding for implementing changes to enhance production, despite the fact that the sector is well developed, and located in a region where manpower and supporting infrastructure should not be an issue with implementation. Unless barriers to implementation can be dealt with, the value of any R&D undertaken will be much reduced in the near-term, and opportunities to learn for the future will also be lost.

Table 15.1 – R&D Needs Sorted by Overall Priority

R&D Need Prioritization Spreadsheet

			GHG Criteria					Sustainability Criteria					Combined			
I.D.	R&D Need	Type of R&D	Timing	GHG Impact	Forecasting	Score	Rank GHG	Economic	Enviroment	Security	Score	Rank Sust	Variance	Rank Var	Score	Rank OA
B1.1	Collection and Utilization of Methane	Motivation	1	1	1	3	1	3	4	6	13	11	10	9	16	1
A1.4	Water Influx	Investigation	3	5	5	13	2	2	4	3	9	2	-4	29	22	2
B1.3	Transportation - Pipeline Gathering Systems	Motivation	5	4	6	15	8	5	1	3	9	3	-6	22	24	3
A1.1	Impacts of Intentionally Producing Sand	Theory Development	8	8	1	17	11	1	6	1	8	1	-9	15	25	4
A2.1	Extend Low Energy Primary	Piloting	6	3	4	13	3	3	6	3	12	7	-1	40	25	5
B1.5	Fired Equipment Efficiencies	Field Trials	2	5	7	14	4	5	2	5	12	8	-2	36	26	6
A1.2	Geomechanics in the Reservoir	Theory Development	8	8	3	19	12	2	6	1	9	4	-10	10	28	7
B1.2	Transportation - Enhance Trucking Efficiency	Motivation	3	7	4	14	5	6	3	6	15	19	1	39	29	8
A2.5	Follow-up Processes - Waterfloods and Chemicals	Piloting	6	4	6	16	9	4	6	4	14	14	-2	37	30	9
B3.2	Assessment of Technologies in the Field	Field Trials	3	8	9	20	16	7	2	3	12	9	-8	19	32	10
B2.1	Regional Water Management	Motivation	4	7	8	19	13	5	4	4	13	12	-6	23	32	11
A2.3	Follow-up Processes - Solvents	Piloting	9	5	5	19	14	6	3	5	14	15	-5	25	33	12
B3.3	Support for Local SME and Industry Suppliers	Motivation	3	7	9	19	15	7	3	4	14	16	-5	26	33	13
A2.2	Follow-up Processes - CO2	Piloting	7	4	5	16	10	7	4	7	18	26	2	35	34	14
A1.3	Foamy Oil Production	Investigation	2	4	8	14	6	6	10	4	20	28	6	21	34	15
A3.3	Coupled Geomechanics and Reservoir Simulation	Investigation	10	10	5	25	23	4	6	2	12	10	-13	6	37	16
C1.1	Understanding Water Inflow	Field Trials	4	8	8	20	17	4	7	6	17	22	-3	34	37	17
A1.8	Low Cost Routine Monitoring	Field Trials	8	10	9	27	28	5	4	2	11	5	-16	3	38	18
A3.5	Field Pilots - Reservoir	Motivation	8	8	7	23	21	5	6	4	15	20	-8	20	38	19
A2.4	Follow-up Processes - Air Injection	Piloting	8	6	7	21	18	5	5	7	17	23	-4	30	38	20
B1.6	Development Planning	Motivation	7	9	9	25	24	6	3	5	14	17	-11	8	39	21
C3.4	Implementation to Realize Benefits	Motivation	10	9	10	29	30	3	5	3	11	6	-18	1	40	22
A3.1	Need for Data to Allow Simulation	Data Collection/Analysis	9	10	3	22	20	5	10	3	18	27	-4	31	40	23
A3.2	Cost Effective Quality Reservoir Data Collection	Field Trials	10	10	5	25	25	3	10	3	16	21	-9	16	41	24
A1.9	Potential GHG Impacts	Data Collection/Analysis	5	5	4	14	7	10	8	9	27	41	13	5	41	25
A1.5	Sand Measurement in the Field	Field Trials	10	10	10	30	32	2	9	2	13	13	-17	2	43	26
A3.4	Collaborative Data Analysis	Data Collection/Analysis	10	10	10	30	33	5	7	2	14	18	-16	4	44	27
B2.3	Surface Development - Flexibility and Footprints	Risk Management	9	9	9	27	29	9	1	7	17	24	-10	11	44	28
B3.1	Definition of Problems	Investigation	3	9	9	21	19	8	8	8	24	36	3	33	45	29
C3.1	Field Trials - Equipment/Methods	Field Trials	10	10	10	30	34	6	8	3	17	25	-13	7	47	30
B1.4	Sand Separation	Field Trials	6	10	10	26	26	7	5	9	21	32	-5	27	47	31
C1.3	Controlling Inflow	Field Trials	6	8	9	23	22	7	8	9	24	37	1	38	47	32
A1.6	Reporting of Sand Production	Data Collection/Analysis	10	10	10	30	35	9	7	4	20	29	-10	12	50	33
A1.7	What Should be Monitored?	Investigation	10	10	10	30	36	8	7	5	20	30	-10	13	50	34
C3.2	Shared Funding	Motivation	10	10	10	30	37	6	10	4	20	31	-10	14	50	35
C2.3	Adapting to Potential Recovery Methods	Risk Management	10	10	10	30	38	5	9	7	21	33	-9	17	51	36
C3.3	Data Sharing	Data Collection/Analysis	10	10	10	30	39	7	8	6	21	34	-9	18	51	37
B2.2	Water Treatment and Purification	Risk Management	8	8	10	26	27	9	7	9	25	38	-1	41	51	38
C1.2	Designing Robust Wells	Risk Management	10	9	10	29	31	9	6	8	23	35	-6	24	52	39
C2.1	Tools for Flexible, Controlled Drilling	Field Trials	10	10	10	30	40	7	9	9	25	39	-5	28	55	40
C2.2	Inflow Enhancement - Near Well and Wellbore	Field Trials	10	10	10	30	41	8	9	9	26	40	-4	32	56	41

Appendices

A. Working Group and Workshop Sessions

A1 – March 9 Working Group Notes
A2 – March 10 Working Group Notes
A3 – March 21 Presentation – Introduction and Background
A4 – March 21 Presentation – Methane Vents
A5 – March 21 Presentation – Heavy Oil Transportation
A6 – March 21 Presentation – Reservoir Process
A7 – March 21 Presentation – CHOPS Follow-up
A8 – March 21 Presentation – Field Trials
A9 – March 21 Presentation – Barriers to Implementation
A10 – March 21 Workshop Notes
A11 – March 21 Workshop Feedback
A12 – March 21 Workshop Attendees

B. Prioritized List of R&D Needs

B1a – Ranking Criteria
B1b - CHO R&D Needs List – Combined Priorities
B2 – Needs Prioritization Spreadsheet