CHOPS:

Cold Heavy Oil Production with Sand in
the Canadian Heavy Oil Industry

for

Alberta Department of Energy

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by

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SOME RECOMMENDATIONS RELATING TO ALBERTA HEAVY OIL

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1. Royalty/Taxation Regime

Currently, there is a different royalty and taxation regime north and south of Township 53 in Alberta. This is based on an "oilsands" classification that is a possible classification for oil producers north of Twp 53, providing them with a more beneficial royalty status. Their production with CHOPS (or with horizontal non-thermal technologies) is referred to as "primary bitumen production". Not considering this geographic definition, the lower boundary for this federally and provincially defined status as "heavy oil" or "bitumen" appears to be 10,000 cP (centiPoises) viscosity. However, precisely the same technology is used south of Twp 53 (CHOPS) for the great majority of the production, yet producers cannot access the lower royalty rate. Instead, it is classified in that area as "primary heavy oil production".

This condition seems anomalous. Perhaps the EUB should examine the possibility of classification in terms of viscosity throughout the province, and affixing a royalty regime based on that. Another possibility is the affixing of a royalty regime based on the particular technology used (CHOPS, SAGD, VAPEX, CSS…). Either of these approaches would result in fewer anomalies that currently arise because of an arbitrary geographical boundary.

The writer suggests a much more uniform royalty regime based on several divisions (the following are personal examples only):

- Heavy oil or oil sands (all oil >100 cP in situ viscosity), non-thermal extraction,
- Heavy oil or oil sands, thermal extraction (the issue of what thermal source is used arises, as methane is a valuable resource in its own right),

Experimental projects that meet certain standards with respect to attempts to commercialize new technical methods for improved or more economical extraction.

2. Survey of CHOPS Economic and Recovery Impact

The writer estimates that approximately 460,000 b/d of Canada's total petroleum production comes from Cold Heavy Oil Production with Sand (CHOPS). This represents 22% of Canada's total oil. Yet, remarkably little attention has been directed to this technology, compared, for example, to surface mining or thermal recovery methods.

The NEB believes that there are 75 billion barrels of oil recoverable from the resource base of 350 billion barrels of oil in the Heavy Oil Belt. The writer believes the final figure will be much closer to 150 billion barrels, even limiting one's assessment to currently existing technologies, including pressure pulsing, CHOPS, and SAGD.

The only reason that there is currently a limit on about 460,000 b/d production of heavy crude oil from the Alberta and Saskatchewan heavy oil belt this figure is the lack of upgrading facilities in Canada. If upgrading facilities were available, the writer believes that Canada could sustain two to three million barrels a day of heavy oil production from the Heavy Oil Belt alone. This production rate could be sustained for at least 100 years. Many old fields that have only produced 5% of OOIP would be re-entered and placed on additional phases of recovery. New technologies currently emerging (VAPEX, THAI, hybrid methods) could be applied to these suspended reservoirs. The favored technology appears to be CHOPS, especially for thin reservoirs without active bottom water zones. The efficiency of this process can be improved with the use of pressure pulsing to aid recovery and to increase the technological viability of processes such as waterflooding. Even in old fields that have produced substantial amounts of oil and are not currently on production, it may be attractive to use existing wells to attain better recovery ratios.

It is recommended that the EUB institute a study of CHOPS efficiency and operating costs. It may be difficult to have companies participate actively in this, and the cost figures for various oil fields will have to be kept confidential.

To execute this study, it will be necessary to do analysis of reservoirs so that they can be classified in terms of the most suitable technology for increased recovery ratios. Also, the production histories of individual wells and individual fields should be drawn together, along with information such as changes of technology (many fields were converted to aggressive CHOPS approaches in the 1990's)

3. The Issue of Upgrading Capacity

At least 300,000 b/d of heavy crude are exported to the USA for upgrading and sales. This requires as well the addition of large volumes (up to 15% for the most viscous crudes) of diluent, otherwise known as naphtha, a mixture of light aliphatic hydrocarbons. The crude is shipped to upgrading and refining facilities in Chicago, Minneapolis, Kansas City, Billings Montana, and several other smaller facilities that have been redesigned over the years to accept a heavier feedstock. These heavy crude oils are upgraded using a combination of coking for carbon rejection and hydrogenation to increase the H:C ratio so that transportation fuels (gasoline, diesel and jet fuel) can be produced.

Currently, upgrading facilities are operating near capacity, but independent producing companies (those without their own upgrading facilities) are maintaining shut-in capacity because of a glut of production. Because of the shortage of upgrading capacity in the existing markets, the price given to producers in a competitive market has been quite low at times, increasing the profits to the upgrading facilities massively. For example, for much of 2001, the differential purchase price between light crude and heavy oil was greater than CAN$15.00/bbl. A quick calculation shows the impact on Canada and Alberta.

- Assume the upgrading facility needs CAN$8.00/bbl to be reasonably profitable.
- Assume 300,000 b/d of heavy crude goes to the USA.
- Assume a differential that averages CAN$15.00/bbl over the year.
- The difference of approximately CAN$760,000,000 per year makes upgrading facilities in the USA extremely profitable.

Also, this simple analysis does not include the massive benefits in doing all of the basic upgrading here in Canada so that the entire CAN$15.00/bbl stays in the Canadian economy, generating more employment and having a multiplier effect on the gross provincial product.

Under no circumstances does the writer recommend arbitrary controls on resources flow, but this issue should be carefully assessed. For example, it is estimated that the total value lost to Alberta, including Canadian companies or non-Canadian companies that operate in Canada, is well over a billion dollars per year. This amount could be used to generate about 50,000-60,000 b/d of additional upgrading capacity each year for Alberta heavy oil production.

Furthermore, there is a pernicious cycle that ensues because of the cyclicity of the heavy oil industry:

- Producers over-produce so that upgrading companies have a glut, and differentials increase.
- The fluctuating price of oil means that the margins for the producers may well drop below the level of profitable production.
- To sustain cash flow, independent producers continue to ship oil at a loss, until their balance sheet suffers, and larger companies buy them out.

The writer recommends that the EUB and the Alberta government revisit this issue. The lost profits and the lost opportunities are simply too large to ignore.

4. Technologies and Resource Recovery Efficiency

Ultimately, the EUB must act as a conservation authority. Thus, it has the role of encouraging best economic practice in oil production to protect the resource base.

This raises several questions in terms of extraction efficiency.

- When does the EUB wish to exercise its mandate over production to encourage technologies that maximum long-term resource extraction efficiency?
- Can the overall economical efficiency of an extraction process be exclusively the purview of a producing company, or should the EUB develop a weighting procedure?

There are several examples that could be chosen to demonstrate that these questions have merit, and that the actions undertaken by a regulatory agency now can have ramifications in the future. Only one example will be developed.

In the past, before the advent of the new heavy oil production technologies that have been developed almost exclusively in Alberta in the last 15 years, the difficulty of producing heavy oil was so great that the issue of recovery ratios did not arise. Getting any oil out of these difficult reservoirs and maintaining profitability was considered a remarkable feat. So difficult was the task that only companies with extremely low overhead structures (local producers) were able to sustain their activities in heavy oil through the price cycles. Imperial Oil was the only substantial exception to this rule, and being an integrated oil company, they had the privilege of being able to generate returns on all aspects of the industrial process: production, upgrading, refining and marketing. Also, in the Cold Lake deposit, Imperial Oil had access to one of the most homogeneous and richly saturated reservoirs that exist in Canada.

However, new technologies promise better recovery ratios, and some technologies are better in certain reservoirs than are others. For example, it appears that in most cases in thin reservoirs (<8 m) that have been developed with long non-thermal horizontal drains, CHOPS would have been a better choice from the point of view of resource recovery, yielding perhaps 12-16% of OOIP rather than 8-10% of OOIP. Yet, companies developing fields where either technology was feasible tended to use horizontal drains because these gave higher early production rates, despite having lives of only 3-5 years.[1] These decisions are predicated on the basis of quick payback and discounted cash flow analysis (oil that can be produced 15 years hence has little value today). Because the economics are not radically different (CHOPS is invariably a close alternative), would the EUB be justified in taking a more proactive approach as to what technology might be employed?

A detailed study of the ultimate value of horizontal wells versus vertical CHOPS wells in thinner heavy oil reservoirs is warranted, as well as a number of other studies of similar issues. Note that in the thinner reservoirs, thermal technologies and gravity drainage methods are not likely to be successful and therefore are not competing technologies, whereas for thicker (>15 m), uniform strata, there are several other technologies that should be co-evaluated, as well as the possibility of implementing one technology after the other, or simultaneously, in a hybrid approach.

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[1] In the writer's view, it may even be the case that CHOPS would have been the economically superior choice because of the low costs of installing vertical wells.

5. Suspended Wells

There are approximately 6000 inactive wells in heavy oil fields in Alberta that are not plugged and abandoned, but which have gone through an initial phase of production, usually at low rates and invariably with less than 10% recovery in the field (often as low as 3-4%). A well that is suspended but not plugged represents a “potential”, but non-productive asset. As time goes on, corrosion and other factors deteriorate the value of the asset, and it must be discounted even more because the well also may not be suitable for a new technology that has recently emerged as a commercial process. Furthermore, there is a risk to the conservation and regulatory agencies that such wells may become liabilities in the future, particularly if the company that owns them ceases to do business and the facilities do not pass into the hands of other viable companies. All unplugged wells will leak eventually, and even many wells that have been properly abandoned according to P&A guidelines will eventually slowly leak natural gas up to the surface outside of the casing.

The suspended wells represent therefore carry risk and a decaying economic value. Perhaps they also represent a resource development value that has significant in the context of conservation and maximum utility of the fixed natural resource base.

The issue of a lack of upgrading capacity is related to what can be produced, and producers seek to maximize their current profits by producing only from those wells that have the lowest operating costs, a reasonable approach. However, if more production capacity (upgrading capacity) becomes available, it seems that it would be justified to explore the possibility of incentives to rehabilitate old inactive wells, rather than drill new ones. New extraction technologies and workover methods have become available for these wells (e.g. pressure pulsing, CHOPS), and the cost of rehabilitating or recompleting an old well is on the order of CAN$40,000-60,000, compared to the cost of drilling and completing a new vertical well (~CAN$200,000).

The writer recommends that a study be commissioned in this area to assess whether there is additional value (increased utility) to the province in developing a policy of encouraging the redevelopment of old wells. Of course, in terms of their own corporate interests, companies will argue that all such decisions must be left entirely in their hands, but in light of the rapid recent technological changes in the heavy oil producing business, this position is shifting.

6. Use of Natural Gas as a Fuel for Thermal Recovery

Methane production in Alberta will peak in the near future (several years). In North America as a whole, the peak is probably about a decade away, and for the world, about 15 years away. Methane is used as household fuel, but it has several other important uses that will impact demand for methane in the future.

Methane (CH_4) is the precursor to methanol (CH_3OH), which is the hydrogen source for fuel cells. Thus, as fuel cell technology starts to make a minor impact on transportation fuel use approximately 15 years from now, pressure will increase on the use of methane as a source of H_2.

Methane is an excellent short-response energy source, particularly for emergency power generation. Installation of natural gas turbines in buildings that cannot afford to have power interruptions for long periods (computer centers, hospitals…) is happening in California and elsewhere. This is a "premium" use for methane, and such installations are increasing in number.

Methane has a profound value for Alberta in the future as a hydrogen source for upgrading heavy oil (hydrogenation). As Canadian heavy oil and bitumen production continues to rise, the consumption of methane in these facilities will grow proportionately. There appears to be no other technologically viable hydrogen source on the horizon.

Therefore, because of these three major uses of methane that give additional benefits above the basic thermal energy content alone, it is of interest to the EUB to examine use of CH4 in applications where it can realistically be displaced by other energy sources. For example, burning large amounts of methane to generate heat for thermal heavy oil extraction processes can perhaps be changed. Two possible alternatives are coke (or natural coal) combustion and heat co-generation from nuclear power stations.

Coke is a byproduct of the upgrading processes for heavy oil, and with fluidized bed reactors, combustion without noxious emissions is feasible. Limestone is used in the fluidized beds to capture sulphur (2CaCO3 + 2S + 3O2 $\rightarrow$ 2CaSO4 +2CO2). The CO2 from the fluidized bed reactors may be able to be separated and sequestered in various geological media. In the heavy oil and bitumen area of Alberta, the Lotsberg Salt at a depth of 900-1350 m represents a massive resource for sequestration in salt caverns, and the dissolved salt (brine) has some commercial value.

Also, Alberta should foster basic research on seeking another hydrogen source for the heavy oil upgrading technology area, or alternatively other methane sources n the long-term.

The EUB has the mandate to optimize the return to Albertans from the natural resource base, and this is one area where future market forces in a changing energy deployment scenario may have a dramatic impact. The EUB should explore these issues.

7. Reporting Sand Volumes and Waste Volumes Monthly

CHOPS technology is an effective way to exploit the heavy oil in many of the unconsolidated sandstone reservoirs ranging from south of Cold Lake to southern Alberta (as well as the reservoirs west of the Cold Lake Oil Sands area). However, CHOPS generates large amount of wastes that have no commercial value and that represent a substantial additional environmental liability if improperly disposed. These wastes are mainly the following:

- Large volumes of sand containing from 1% to perhaps 5% oil by weight. Approximately 30-40 kg of sand are generated for every cubic metre of oil produced.
- Stable emulsion, consisting of a mixture or oil, water, and fine-grained minerals such as clays. Approximately 3-5 kg of emulsion are generated for each cubic metre of oil produced.
- Tank sludge, consisting of a mixture of emulsion, additional asphaltenes, and fine-grained sand.

Currently, the technologies to dispose of these wastes are limited to landfill placement, salt cavern disposal, and slurry fracture injection for the oily sand. Other technologies are either environmentally damaging or are extremely expensive (e.g. sand washing). For the emulsions and the tank bottoms, landfill placement is not an option because of the fluid nature of these materials. They have to be treated in expensive separation processes such as centrifuge treatment or heat separation.

The EUB should require that all operators separately report the volumes of sand produced and the volumes of emulsion and tank bottoms generated. Sand volumes are easily determined from trucking tickets that are generated during the cleaning of the production stocktanks. Emulsion and tank bottoms volumes (or weights) are determined mainly at batteries, and may also be determined from truck tickets.

The ADOE should consider supporting research into the direct combustion of the oil rich emulsions and tank bottoms. Fluidized bed technology with limestone to capture sulphur seems to be the most feasible approach for combustion, and the heat generated can create power or steam for thermal processes such as SAGD. A central facility or several small facilities to accept these wastes should be constructed in an optimum location where the thermal energy will have the greatest value (also displacing CH_4 combustion for heat). The residual solids can be placed in landfills, and the CO_2 from this point source could be captured and sequestered.

Collection of sand data will permit the EUB to track the generated volumes of this waste material, and this will help in developing guidelines for long-term environmentally benign disposal. It is clear at this time that there will not be an economically viable technology that would permit the separation of the small amount of oil from the sand, and any such process would still have to deal with several additional waste streams.

Under the existing regulations, the EUB has the authority to make these requests of oil companies.