

The Oil Drum: Net Energy

Discussions about Energy and Our Future

Unconventional Oil: Tar Sands and Shale Oil - EROI on the Web, Part 3 of 6

Posted by [Nate Hagens](#) on April 15, 2008 - 11:00am in [The Oil Drum: Net Energy](#)

Topic: [Supply/Production](#)

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This is third in a series of six guest posts by [Professor Charles Hall of the SUNY College of Environmental Science and Forestry](#) describing the energy statistic, "EROI" for various fuels. As has been discussed often on this site, [net energy analysis](#) is a vitally important concept - just as we primarily care about our take home pay which is our salary minus the taxes, we should care about our 'take home' energy, which is what is left after energy costs have been accounted for. As important as it is, this measure is not easy to quantify, as: a) data is almost always measured in \$ as opposed to energy terms, b) parsing non-energy inputs (and outputs) into energy terms is difficult, and c) analysis boundaries (including environmental impacts) are very disparate. As such, there is not (has not yet been) a consistent formula for EROI applied to all energy studies that has led to policymakers and analysts speaking the same language in useful ways. The lead paper in this months Royal Academy of Sweden's journal AMBIO will be about such an EROI framework, and we will link to it when it comes online.

Professor Hall has been working in this area for over 30 years. Below are net energy analysis from Hall's group on the unconventional oil sources from tar sands and oil shale two resources that theoretically are enormous in energy scale, but practically are limited by flow rates, costs, and externalities. Just how limited is the subject of today's two-part informative post is below the fold. Remember, any specific numerical help via referenced literature, personal experience or knowledge to better inform Dr. Hall and his students would be appreciated.

Previous articles/commentary from this series:

[At \\$100 Oil, What Can the Scientist Say to the Investor?](#)

[Why EROI Matters \(Part 1 of 5\)](#)

[EROI Post -A Response from Charlie Hall](#)

[EROI Part 2 of 5 - Provisional Results, Conventional Oil, Natural Gas](#)

APPENDIX D TAR SANDS/OIL SANDS

M.C. Herweyer, A. Gupta

Definition

Oil sands, also called tar sands, consist of bitumen mixed with sand. Bitumen or "very heavy" oil is composed of carbon rich, hydrogen poor, long chain molecules and is in a semi-solid or solid form. It has not been "cooked properly" by geological processes to yield the lighter fractions we

call oil. It is familiar to modern humans as the black constituent of asphalt used for roads and shingles. Generally its API (a gravity or density scale developed by American Petroleum Industry) gravity is less than 10 API, and its viscosity is so high that it does not flow naturally (higher than 10,000 cPo) (Briggs 1988). As a comparison, conventional crude oil has an API gravity of about 30-40, and a viscosity of 5 cPo. The product produced by mining and processing tar sands is usually called syncrude (Syncrude is also the name of a company that produces the product).

Distribution and history of use

Bitumen is found more or less wherever petroleum is found, although by far the largest deposits are as tar sands. About 81% of the extractable oil sands of the world are found in Canada (AEUB, 2003). Venezuela also has large resources but it is heavier, of much lower quality and very difficult to extract. The ancient Mesopotamians used bitumen or asphalt as an adhesive in activities from sticking arrowheads on shafts to architecture, although its use was always limited. The oil sand history started with the development of oil sand separation in the 1920s by Dr. Karl Clark. In 1936 Max Ball developed a way to produce diesel oil from it. The actual commercial production started in 1963 when the Sun oil company – later Suncor – started the construction of the first commercial oil sand production plant. The first barrel of commercial production by open pit mining was produced in 1967 (Syncrude 2006). The more complicated in situ techniques started their production of sand oil in 1985. After the rise of crude oil prices in 2003, investments in oil sands production tripled over the years and it has become a booming business.

Technology

The oil sands can be extracted in two ways: open-pit mining for oil sands located on or just below the surface, and **in situ** recovery for oil sands located underground. About 80 percent of the oil sands are located deeper than 70-80m below surface and some large proportion can be extracted but only via in situ techniques (Mawdsley et al. 2005). The remaining 20% can be extracted by open-pit mining techniques. After the excavation or drilling, bitumen is extracted from the remaining mixture of sand and water. About two tons of tar sands are required to produce one barrel (roughly 1/8 of a ton) of oil. The next phase is either to use hydrogen to upgrade the bitumen to 300 API syncrude, which has a quality comparable to conventional crude oil, or to blend it with higher quality diluents such as conventional oil. Both these products can be refined at existing refineries. An important issue is the degree to which natural gas is required either for process heat or for upgrading the quality and reducing the viscosity of the bitumen.

Surface mining

The only operational Canadian open-pit mining process which excavates the oil sands is the truck and shovel technique. After excavating, the extracted material is treated ex situ (above ground), first in a separation plant and then in an “upgrader” plant. The first step in the ex situ treatment cycle is the sizing process, where the biggest pieces are broken into smaller ones by a crusher. Then the bitumen is separated from the water, sands (quartz), and clays by a water-based conditioning and flotation process (Schramm et al. 2001).

Underground mining

There are four main in situ techniques that can be used for extracting oil sands located deeper than 70–80m below surface. The most common techniques are Cold Heavy Oil Production on Site (CHOPS) and Steam Assistance Gravity Drainage (SAGD). The Cyclic Steam Stimulation (CSS) method was developed and used, but recently proved to be inefficient. The fourth technique, the Toe-to-Heel Air Injection (THAI-TM) is in a late stage of development and is thought to be efficient and productive. Finally, a pilot project under the name “Orion” run by Petrobank will probably start to produce in 2008. (Petrobank, 2004; NEB, 2006)

The **CHOPS** process does not filter out the sands at the production wells, but instead pumps the sand fraction up along with the bitumen and water. It is commonly used for extra-heavy oil production but not as much in the production of oil sand (for later separation) because the oil sand bitumen is too viscous to pump using CHOPS.

The **SAGD** technique uses two horizontal wells. Steam is injected in the upper well to heat the oil sands and lower the viscosity of the bitumen, and the lower well is for pumping out the bitumen. Light crude oils or natural gas are used as solvents to capture the condensates in the steam gas. This process is called Vapor Recovery Extraction (VAPEX) and the Solvent Aided Process (SAP) (Conti et al. 2006, Mawdsley et al. 2005).

The **CSS** technique uses either one horizontal or one vertical drill to inject steam into the oil sand-field to pump the fluidized bitumen. The cycle starts by pumping in the steam in the *steam injection phase* and then heating up the viscous bitumen in the *soak phase*, which takes three to four weeks. Finally, the fluidized bitumen can be pumped up in the *production phase*. Once this cycle is completed the process starts all over again at a new site.

The **THAI-TM** technique is a combustion process which uses a vertical air injection well and a horizontal production well. A fraction of the bitumen in place is burned with the inserted air so that the remaining bitumen will warm up and attain a lower viscosity (Mawdsley et al. 2005). The fluidized bitumen then flows down to a collecting pool and is extracted by the production well.

Another method which can be used in combination with one of the above mentioned techniques is the Pressure Pulse Flow Enhanced Technique (PPT). This is not an extraction technique, but one that stimulates extraction. PPT is based on the discovery that large amplitude and low frequency wave energy will enhance flow rates in porous matter (Dusseault 2002).

The next conversion step to obtain syncrude is called upgrading, which typically consists of two steps. The primary **upgrading** is based largely on “coking” and “catalytic” (hydro) processes by a coker and/or an ebullated bed hydro process. The primary process will crack the larger bitumen into lighter products, but the process will leave a significant amount of sulfur and nitrogen compounds in the lighter products and a secondary process is needed. The secondary upgrading process is based on hydro processing by one or more hydro processing units (Alberta Chamber of Resources 2004). After going through these processes the API gravity is about 300 API. About 1.16 barrels of bitumen and 28 cubic meters of natural gas are necessary to produce 1 barrel of syncrude by this method. Both mining and InSitu operations also use large volumes of water for their extraction process. Between 2 and 4.5 volume units of water are used for the extraction of one volume unit bitumen (National Energy Board 2006). There have been some proposals for the use of nuclear power to provide process heat.

Resource base

According to the Alberta Energy and Utilities Board (AEUB 2003) the initial volume of crude bitumen in place is about 1.7 trillion barrels, which is the total for Canada. About 11% or 175 billion barrels are thought economically available for extraction (National Energy Board 2006), but according to Syncrude (Syncrude 2006), the recoverable fraction could rise up to 315 million barrels with advanced techniques.

Currently 36 different oil sand projects are either already operating or under development in Canada. The smallest production is coming from the projects Great Divide and Halfway Creek, which are run by Connacher and ValueCreation, respectively. Their production capacity is about 10 thousand barrels of bitumen per day (kbb/d) and they both apply InSitu recovery technique. The Horizon mine has the largest production capacity with about 500 kbb/d and is run by the Canadian National Resources Limited (CNRL).

Many of these operations use InSitu techniques despite the fact that open pit mines are easier to initiate. There are three principal reasons to use InSitu:

- 1: Only 20% can be extracted by an open pit technique, because the rest of the resources are located deeper than 70 meters below surface (too much over-burden).
- 2: The economic costs of InSitu are marginally cheaper than the open-pit mining. Because the most optimal mining locations are already in use, InSitu will be cheaper for new investments.
- 3: After the InSitu excavation the product is mainly bitumen (with some fractions of water and aerosols left in), while the excavation product from surface mining is mainly sand with about 10% bitumen. External sand/bitumen separation is necessary, and this is a difficult and expensive process.

The production volume of the oil sands is expected to grow steadily. The production in 2005 was almost 1 million barrels of bitumen per day (Herweyer, 2007). In 2020 the production is expected to be 4.9 million bb/d if there are no major problems such as environmental restraints on production. Despite the fact that only 20% of the total oil sand resources can be extracted by the mining technique, the ratio of mining to InSitu recovery is about 50/50. This is expected to stay approximately equal until 2020 (Herweyer, 2007). Even at 5 million barrels per day or about 1.5 billion barrels per year (representing about 25 percent of current US use) the 175 billion barrels of reserves would last for at least 100 years. The limiting factors, if any, are likely to be not the tar sands but the associated hydrogen, water requirements and environmental impacts. It is likely to be a rate limited, rather than a resource limited, process for some time. A factor that is rarely mentioned is that about half of the increased production is necessary to compensate for the decline of existing conventional wells which were recently the dominant source of oil in Canada.

EROI

Methodology

The issue of EROI is different from most other fuels because the energy source for the process is from the resource itself and it has no other alternative economic uses. This is different from “diverting” energy either from society (e.g. to mine coal or grow a biomass fuel) or from a situation where the energy could be immediately used by society (natural gas used at a petroleum well to run a pump vs being piped to society). The oil sand EROI is calculated by the following formula, although only direct and indirect input energies tend to be used by most analysts:

$$EROI = \frac{E_{output}}{E_{input}} = \frac{E_{boe}}{(E_{direct} + E_{indirect} + E_{Labor} + E_{env.})}$$

Where: E_{output} = E_{boe} = Energy content of one barrel of oil equivalent (6164 MJ)

E_{input} = Total energy input (MJ/boe)

E_{direct} = Direct energy demand (only the energy flows) (MJ/boe)

$E_{indirect}$ = Indirect energy demand (e.g. energy to make capital equipment) (MJ/boe)

E_{Labor} = Labor energy demand (Includes labor and maintenance) (MJ/boe)

$E_{env.}$ = Environmental energy demand (Kyoto protocol, others) (MJ/boe)

In this case the energy output is relatively simple to calculate as it is equivalent to the energy content of one barrel of crude oil. The energy input, however, is more complicated. We determined the energy content of the different processes involved within the research boundary (extraction, separation and upgrading) separately by a “bottom-up” accounting framework approach. The direct energy is efficiency corrected (i.e. primary electricity is multiplied by three) and calculated in MJ. It is not calculated back to all primary energy used e.g. if diesel was used in the process, the energetic extraction, refinery, and transportation cost of that fuel is not calculated. Rather only the energy content of diesel is used as a parameter. Thus the EROI numbers we generate are conservative (i.e. higher than if more comprehensive boundaries are used).

We determined the indirect, labor, and environmental components of the EROI, used in sensitivity analysis, by calculating the total dollar costs per barrel for each of these sectors (see Figure 2) per boe and then multiplied by the energy value per USD2006. Indirect energy includes capital costs per boe (corrected for the capital recovery factor). Labor includes only the direct labor and maintenance per boe. Environment costs include the CO2 emission trading cost per boe (from the Kyoto protocol) as an indicator for the GHG emission costs, and an assumed socio-environmental costs for the impacts to the direct surroundings.

Results

By our admittedly incomplete calculations the EROI depends mostly upon the direct energy used and which alone suggests an EROI of about 5.8:1 (Figure 1). Including indirect energy decreases the EROI to about 5.2:1, and adding in labor and environmental costs have little effect. A comparison with the limited other data out there indicates that our analysis generates a somewhat higher EROI than others (Table 1). Nevertheless it appears that tar sands mining yields a significantly positive EROI.

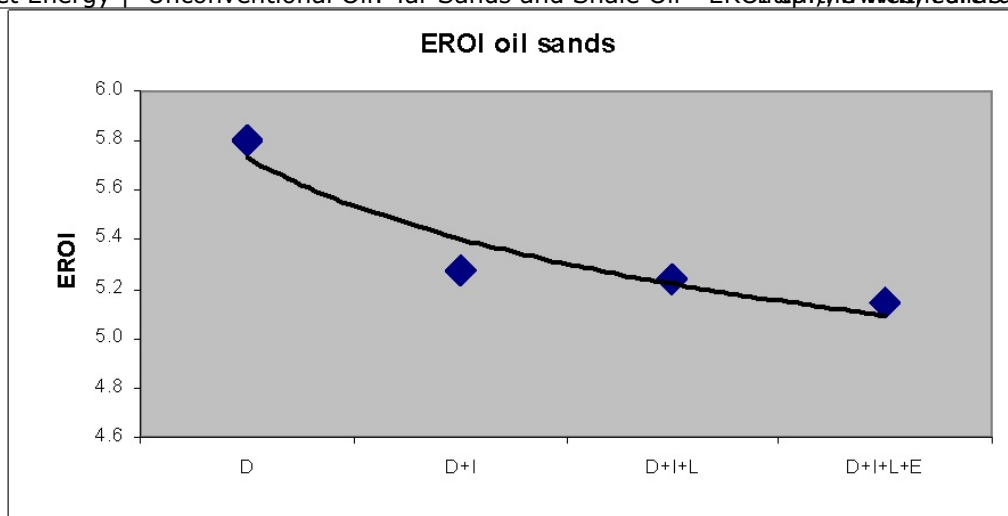


Figure 1: EROI for oil sand production. *D* represents only the direct energy flows, *I* represents Indirect energy flows, *L* represents Labor energy demand, and *E* represents the Environmental energy demand.

Click to Enlarge.

Author	Date	Technique	Resource	System Boundary	EROI
Kymlicka, W.	2006	-	Alberta	-	<5:1
DOE	2006	surface; in situ	Alberta	-	7.2:1; 5:1
Günther, F.	2008	-	Alberta	Shallow sands	1.5:1
Heinberg, R.	2003	-	-	-	1.5:1
Swenson, R.	2005	-	-	-	3:0:1
Homer-Dixon, T.	2005	-	Alberta	-	4:0:1
Sereno, M.	2007	-	-	-	1-3:1
Legislative Peak Oil and Natural Gas Caucus	2007	-	Alberta	-	3:0:1

Table 1: Other Analyses of Oil Sands EROI

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Economics

The average production cost of one barrel of syncrude from the oil sand resources in Canada was approximately 32 USD in the year 2006. The mining process costs about 16 USD2006/barrel of oil equivalent (boe). The InSitu SAGD extraction costs about 14 USD2006/boe, and the upgrading process to syncrude costs about 16.5 USD2006/boe. Figure 2 shows the break down of the total costs that were incorporated in the EROI calculations above (Herweyer 2007). Mining costs appear to be decreasing according to some reports in early 2008.

Syncrude has approximately the same quality as conventional crude oil, and is therefore competitive. So long as the conventional crude oil price stays above 31.5 USD2006/boe (excluding profits) it is profitable to extract oil sands. The conventional crude oil prices in 2006 were 56 and in 2007 as much as \$80 USD/boe (BP 2006). However at the same time the price of diesel, natural gas, steel and so forth used in generating the syncrude were increasing. Nevertheless it appears that tar sands will be a competitive source of oil for the indefinite future.

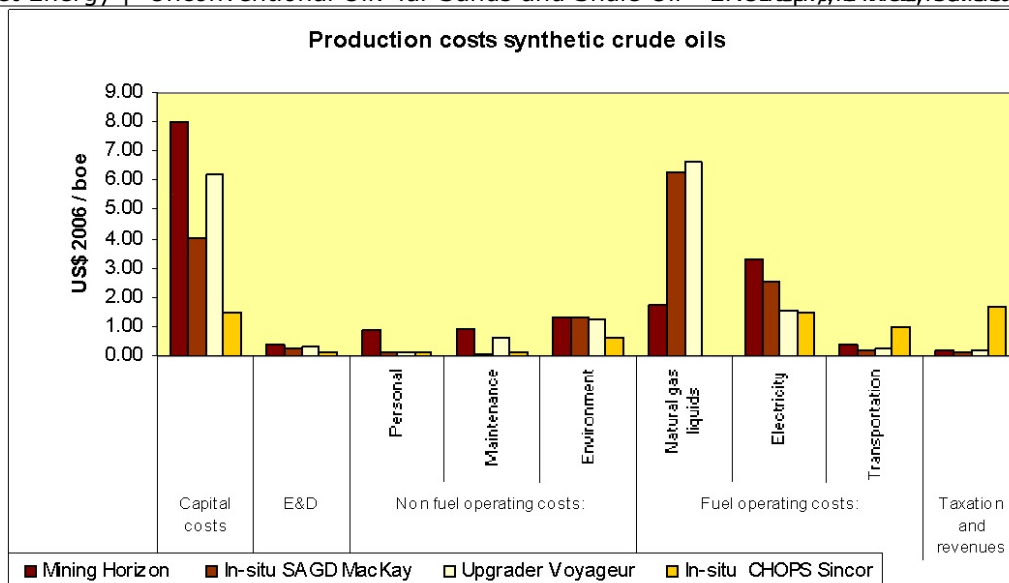


Figure 2: A break down of the production costs of a case study about synthetic crude oils. Note that the mining, InSitu SAGD, and the Upgrader processes are located in Canada and based on Oil Sands, and the InSitu CHOPS is located in Venezuela and is based on Extra-Heavy Oil. The total cost is roughly 32 dollars per barrel of syncrude.

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Capital costs and natural gas liquids are the most monetary cost-intensive inputs of the production of oil sands (see Figure 1). Both these products are also considered very energy-intensive. Therefore the production cost of oil sands is closely related to the costs of energy.

The Alberta oil sands tax regime is such that it makes it very appealing for investors to put their money into oil sands business. The attractiveness in the fiscal regime is that until all original capital (plus a return) is recovered, only a production royalty of 1% of revenue is required. After the original capital is earned back by oil sand recovery, a royalty of 25% of net operating income is required. The tax regime is such that essentially no income tax has to be paid until all capital costs are recovered (TD Securities 2004).

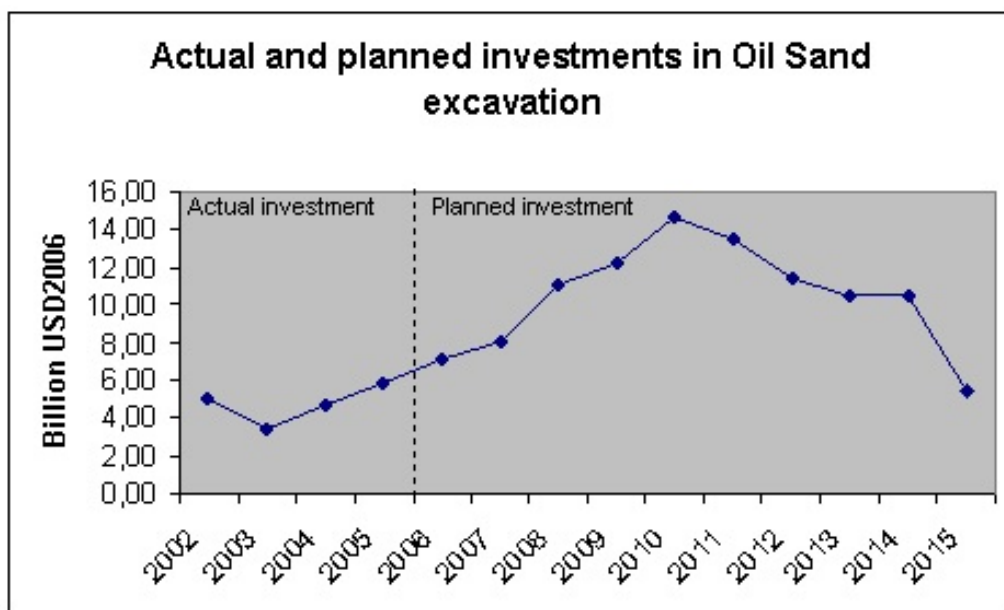


Figure 3: Actual and planned investments in Oil Sand Excavation projects. (Source: NEB, 2006)

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Socio/Environmental aspects

Canada has an open market based economy with favorable conditions for oil sands investments, so that production volume can increase rapidly.

In 2002 Canada agreed to reduce their greenhouse gas emissions (GHG) emissions by 6% compared to their 1990 emissions in the Annex I period of the Kyoto protocol (2008 – 2012). By 2004, however, the GHG emissions had already risen by 28% above 1990 levels (Commission Environmental and Sustainable. 2006). In 2006, Canada declared it could not meet their Kyoto targets and even considered removing policies designed to meet the targets.

The oil sand industry is one of the major GHG emitters in Canada and the entire process approximately doubles to triples the amount of CO₂ released per barrel of petroleum used compared to conventional extraction. The mining process emits about 35 kg CO₂ equivalent/barrel, and the upgrading process 45 kg CO₂ equivalent/barrel, and the SAGD process 55 kg CO₂ equivalent/barrel, (Bramley et al. 2005). In the business as usual scenario for the GHG emissions per barrel of bitumen, the total oil sand GHG emissions until 2020 are as follows: (Herweyer 2007).

Green House Gas Emissions	Total Green House Gas emissions (million Tonne CO2e per year)															
Oil Sands	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Excavating Mining	14	16	18	22	28	31	36	41	43	43	44	49	50	52	52	
Excavating InSitu,SAGD (oil sands)	10	13	16	19	23	29	35	39	42	46	47	47	47	47	47	
Upgrading Oil sands & Extra heavy oils	24	28	33	39	47	53	61	68	73	76	78	82	83	84	85	
Total Oil Sand Excavating+Upgrading	49	57	68	80	97	113	132	148	157	164	168	178	180	182	184	

Greenhouse gas emissions from Candian Oil Sands

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According to the National Energy Board (2006), natural gas use will increase from 0.7 billion cubic feet per day in 2005 to 2.1 billion cubic feet per day in 2015. Although Canada has natural gas resources, this enormous rise in natural gas demand will be difficult to meet. The current capacity of the natural gas infrastructure and production will not be sufficient to keep up with these rises and might present a problem. In addition, the natural gas prices are coupled to the crude oil prices, and so they have risen as well. There is also the large issue of where the natural gas will come from – Exxon is now saying they may not be able to build the necessary MacKenzie pipeline unless they receive significant monetary help from the government.

Both mining and in situ operations use large volumes of water for their extraction process, between 2 and 4.5 volume units of water is used for the extraction of one volume unit bitumen (National Energy Board 2006). Currently the mining operations are licensed to divert 370 million cubic meters (equivalent to 2.3 million barrels) of fresh water per year from the Athabasca river. The planned mining projects will push the cumulative diversion with 529 million cubic meter (3.3

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million barrels) per year (Alberta Environment 2006). Almost all process water ends up in tailing ponds.

Besides the fresh water diversions, the mining operations have a direct effect on the ground water level. Mining pits are excavated up till 70-80m below ground level, which is often below natural ground water levels as well. To prevent water flowing into the mining pit, the groundwater has to be controlled by pumping it up. As a result, the groundwater level of the surroundings is lowered, and the flows are disturbed.

In Canada the most common in situ technique is SAGD, which uses steam to extract the bitumen. This process requires a large amount of water. Although most in situ projects try to reduce fresh water use by mixing with saline groundwater, and recycling about 90 to 95% of the used water, the amount of diverted fresh water is relatively high. In 2004 the in situ projects used 5 million cubic meters (31.5 million barrels) of fresh water, and this will grow to 13 million cubic meters (81 million barrels) in 2015 (National Energy Board 2006).

The gaps that the mining pits leave behind are of such an extent that you can see them clearly in satellite pictures from space. The surface sizes disrupted are enormous.

The decline in unemployment, the increase in prosperity, and the independency in liquid energy supply are positive (economical) social effects, although they are also associated with the familiar issues of boom towns associated with alcohol and sometimes family disruptions.

CONCLUSION

In conclusion, tar sands are an economically and energetically viable, although hardly ideal, approach to maintaining liquid fuel supplies. The most severe problem is probably their local and global environmental impact, and they are already impacting Canadian CO₂ releases significantly. But the tar sands are unlikely to make a large impact on overall supply of liquid fuels because their supply is likely to be rate, rather than total resource limited. If the maximum rate were to grow to about 2 billion barrels a year this would approximately meet Canada's demand and could leave relatively little for export if Canada's production of conventional oil continues to decline. Achieving even this rate of production from tar sands is uncertain because of growing concerns about environmental impacts downstream and insufficient hydrogen and water.

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APPENDIX E. Shale oil

Oil Shale: Potential, EROI and Social and Environmental Impacts.

Gupta, A.K., M.C. Herweyer, and C.A.S. Hall, SUNY-ESF, Syracuse NY.

Definition

Oil Shales are sedimentary rocks containing a high proportion of organic matter, called kerogen, which can be converted to synthetic oil or gas by industrial processing (WEC 2007). According to the Encyclopedia of Energy (Cleveland 2004), oil shale is defined as fine grained sedimentary rocks containing organic matter (kerogen) that yield abundant amounts of oil and gas upon destructive distillation. Although various definitions of oil shale exist, one usual factor is that the kerogen can conceivably be converted into fuel economically, which implies a yield greater than some threshold value, usually in the range of 100-125 l/Mg (1 bbl = 159 L; 1 Mg = 1 metric ton rock) (Burnham 2003). Oil shale recovery is a more difficult process in general than is tar sand recovery because the kerogen bonds more closely to the surrounding substrate.

History

For the U.S., the deposits of oil shale were first studied in detail by the USGS in the early 1900's, after which the government established the Naval Petroleum and Oil Shale Reserves in 1912 that for much of the 20th century served as a contingency source of fuel for the nation's military. Thus oil shale was originally envisioned as a way to provide a reserve supply of oil to fuel U.S. naval vessels (WEC 2007). Its development had always been on a small scale, but the project that was to represent the greatest development of the shale deposits began immediately after World War II in 1946 when the U.S. Bureau of Mines established the Anvils Point oil shale demonstration project in Colorado (Ibid). However, the project ended after it was deemed uneconomical since processing plants had been small and the cost of production high (Ibid).

The most recent attempt at recovering oil from oil shales occurred in response to the Arab Oil Embargo in 1974. Congress responded with a Proposal for Northwest Colorado to be declared a "National Sacrifice Area," including an Energy Mobilization Board with power to override federal, state and local environmental and land use laws (Committee on Resources 2005). This board never materialized. However, President Jimmy Carter did get Congress to establish the Synfuels Corp. with \$15 Billion in price guarantees and incentives (Ibid). The goal for synthetic fuels was an industry that would convert coal, tar sands, and oil shale to liquid fuels at two million barrels per day by 1992, the majority of which would come from Western oil shale (Ibid). Costs were at an average of \$2 billion (1980 USD) for each 50,000 BPD (barrels per day) plant (Ibid). In the end, the oil shale industry collapsed; specifically, due to the huge volumes of material that needed to be removed and processed, the drop in world petroleum prices with which it competed, and the lack of a consistent national vision for the development of the resource that could focus private capital investment (Ibid; Hirsch, Bezdek, and Wendling 2005; US DOE ONPOS 2004). Congress then shut down virtually all oil shale research programs, despite recommendations from many sources that research and development activities continue. In 1991, the Unocal operation in Colorado was the last major oil shale project to suspend operations (Cleveland 2004). For many, the argument about energy was "let the market decide."

Similarly, production from oil shale deposits in South-Eastern Australia began in the 1860's; coming to an end in the early 1950's when government funding ceased (WEC 2007). However, due to a modern exploration program at the Stuart Deposit, it was announced in May 2001 that the first shipment of over 40,000 barrels (5,800 tonnes) of medium shale oil had been made to the south-east Asian fuel oil market (Ibid). That project is currently suspended (Hirsch, Bezdek, and Wendling 2005), and major long-standing shale oil production operations in Estonia, Scotland, Sweden, Canada and China are either gone or dwindling due to high costs relative to petroleum crude oil (Burnham 2003; Cleveland 2004).

Technology

Kerogen is extracted from oil shale in a process called "retorting" which requires heating of the rock to about 900 degrees Fahrenheit. Two generic methods of retorting have been developed which are given here verbatim from the Committee on Resources (2005):

In situ (ICP): This method leaves the rock in place and injects a heat source that releases the oil from the kerogen. The shale oil then flows to a well and is pumped to the surface. The source of the heat is a technical issue still open to research and testing. The only active pilot project in the U.S., owned by Shell Oil, is using down hole electric resistance heaters, but optional technologies involve steam, microwaves, and fire.

Surface retorting: This technology depends upon mined ore for a feedstock. The ore can be either surface mined or mined underground. The ore is brought to a surface facility, crushed and placed into a retort. The shale oil is removed and the spent shale sent for disposal. The shale oil is upgraded by the addition of hydrogen and then is refined conventionally to produce finished products. Several different retort designs have been constructed and tested in the United States as a part of earlier development efforts.

Oil-Tech (OT) currently operates a small capacity, commercial retort in eastern Utah. Their retort has a capacity to process 1 ton of oil shale per hour. On average, one ton of oil shale will produce one barrel of shale oil. The proprietary retort produces 30 degree API gravity oil with a pour point of 53 degrees Fahrenheit (Ibid). After approximately 6 hours of operation, there is sufficient spent shale to enable co-generation so that every 60 minutes approximately 41 tons of 2,500 degree Fahrenheit spent shale is produced – representing a large amount of embodied heat energy potentially useful for other tasks (Ibid).

Also, an experimental "hydroretort" has been designed to operate under a hydrogen atmosphere at higher pressures which increases yields for some oil shale deposits by 200% or more compared to the Fischer assay (a standard laboratory method of determining the quantity of synthetic oil that a sample of crushed oil shale will produce) (Cleveland 2004). However, from an environmental point of view, in terms of topography alteration, water consumption, and greenhouse gas emissions, and despite the significant research and development work conducted 20 to 30 years ago, the industry has not yet reached a consensus on the best technology to use (Committee on Resources 2005).

Finally the Ratheon Company, which had invented microwave ovens, has put forth a plan to use microwaves in situ to cause the oil to flow from rocks in which they are found and into collecting basins. It is not known at this time whether this will work in the field but early results are promising.

Resource base

Oil shale exists worldwide and occurs in nearly 100 major deposits in 27 countries (US DOE ONPSR 2004), including in Australia, Brazil, Canada, China, Estonia, France, Russia, Scotland, South Africa, Spain, Sweden and the USA (Table 1). However, despite periodic predictions that shale oil would soon be needed to replace diminishing crude oil supplies, shale oil production has actually dropped threefold since 1980 (Figure 1; Burnham 2003).

Table 1. Reserves and distribution data on oil shales (from Jiang Han and Cui 2007)

Continent	Known Reserves	Probable Reserves		Total Reserves		
		(10e9 Barrels)				
Recovery (Gal/ton)	25-100	10-25	5-10	25-100	10-25	5-10
Africa	100	Little	Little	4,000	80,000	450,000
Asia	90	14	---	5,500	110,000	590,000
Australia and N.Z.	Little	1	---	1,000	20,000	100,000
Europe	70	6	---	1,400	26,000	140,000
N. America	600	1,600	2,200	3,000	50,000	260,000
S. America	50	750	---	2,000	40,000	210,000
Total	910	2,400	2,200	17,000	325,000	1,750,000

Table 1. Reserves and distribution data on oil shales (from Jiang Han and Cui 2007)

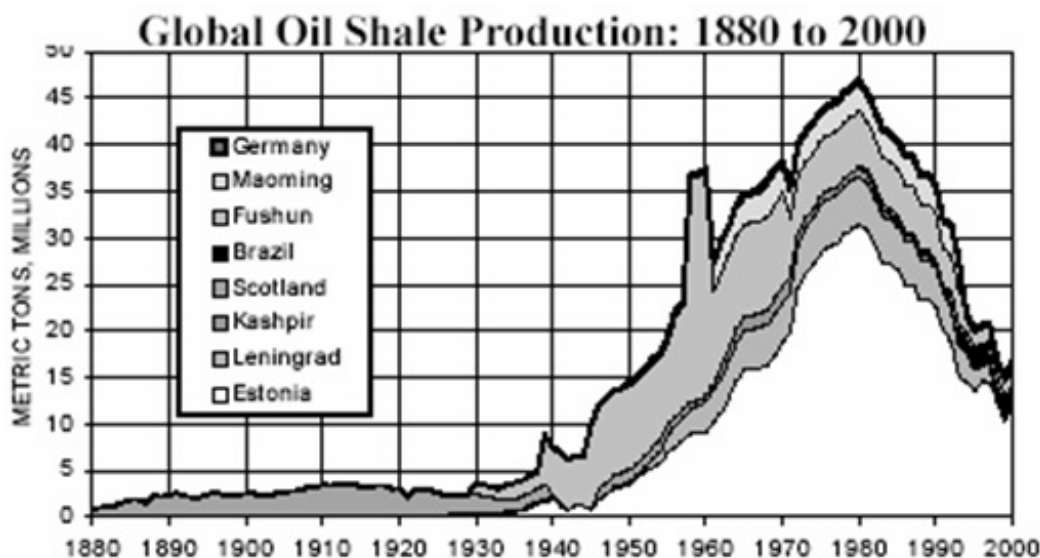


Figure 1. Global oil shale production 1880-2000. (from Cleveland 2004).

As can be seen in the case for U.S., there is a large difference in the quality of the oil shale from place to place (Figure 2). On the high end, commercial grade oil shale from the Green River Formation in Colorado assays at about 0.83 U.S. barrel of oil per short ton of rock (Cleveland 2004). Most other oil shales give lower yields.

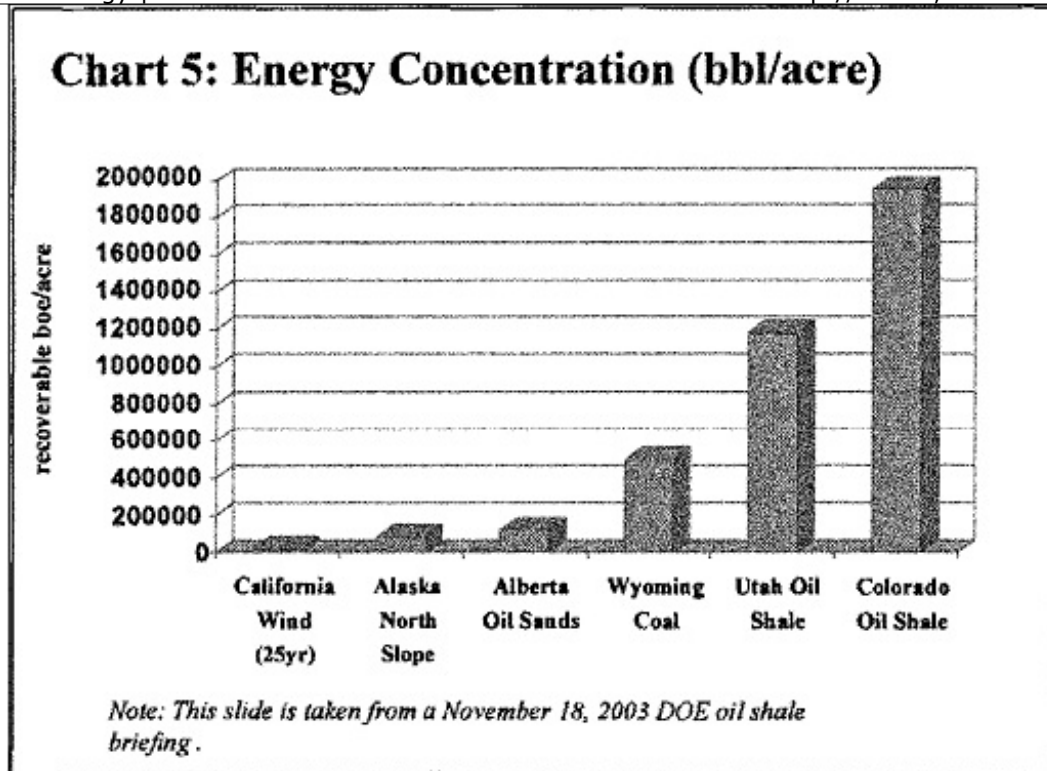


Figure 2. Energy concentration, in barrels per acre thermal equivalents, for various Western fuels. (from Committee on Resources 2005)

In the U.S., shale oil resources might be almost as large as the world's remaining conventional oil resources (US DOE ONPOS. 2004). However, although it is enormous, the main issue is how rapidly this resource can be brought online, especially given water, environmental, and infrastructure constraints. One estimate is that U.S. domestic production of 2 million bbl/day could be possible by 2020 if a new generation of oil shale projects is realized by 2011 (Ibid). However, due to the existence of sensitive Federal lands in the region, such as national parks and forests, oil shale development may be heavily regulated for air emissions, which could constrain the size of the industry and its development (Ibid). A critical issue is the availability of sufficient water, as production and refining of the oil shale is extremely water-dependant. In most areas and schemes a lot of water would have to be pumped uphill significant distances.

Another issue is the capital and the time required to construct facilities. Investment decisions are typically made with 10-year internal rate-of-return calculations, while the resource base supports a physical life of 40 years or more, and so large government subsidies may be needed if capital is to be raised quickly (Ibid). Currently, Shell hopes that first generation commercial start up will occur early in the next decade; however, it will take many years beyond that for the product stream to reach steady state production and profitability (Ibid). Encouragement might be taken by the continued increase in the price of conventional oil, or discouragement from the fact that many huge investments have been made in the past with little oil to show for it, then or now.

EROI

Reported EROIs (energy return on investments) are generally in the range of 1.5:1 to 4:1, with a few extreme values between 7:1 and 13:1. The main difference between oil sands and oil shale is that the oil sands are particles of sand, surrounded by a microscopic layer of water that is itself surrounded by heavy bitumen (thick oil). Separating the oil from the oil sands is much easier

because of this water layer, since the oil is “suspended” in the water/sand layer and not directly stuck on or in the sand as is the case for oil shale. This makes oil shale much more energy intensive to separate (Ibid). As such, shale oil production - whether through surface retorting or ICP - is more energy-intensive than conventional oil production or from tar sands, and even enhanced recovery from oil fields. In fact, upstream energy consumption per unit of final fuel delivered is roughly 1.75-2.75 times that of conventional petroleum production (Brandt 2007). Tar sands and oil shales seem to be in the same “EROI ballpark”.

Shell reports that in their ICP in situ process they consume 1 Btu for every 3 Btu's of energy produced, corresponding to an EROI of 3:1 (Ibid). However, if the energy input is electricity and the output oil this would imply a quality-corrected EROI of close to unity. On the other hand the utilization of natural gas produced during the ICP in-situ process doubles the energy efficiency to 6 Btu of energy produced for each Btu consumed corresponding to an EROI of 6:1. In addition shale oils are a special case, like tar sands, where a large proportion of the energy can be generated from the resource itself (Ibid).

For the mining and retort process, the net energy return (NER) is very low if total energy inputs are counted (NER < 1.5) (Brandt 2006, 2007). In a more recent study, Brandt concludes that the EROI for shale oil production using an ATP retort (a method reported to have the highest conversion efficiency – 88%) is somewhere between 1.9 and 2.5 (2007). However, based on a study in Kentucky USA, if some of the measurable environmental costs associated with shale oil production are included, the EROI drops another 3-9% (Lind and Mitsch 1981). Furthermore, Cleveland concludes that the EROI for shale oil ranges above and below the break even point, depending on assumptions regarding location, resource quality, and technology characterization (2005). The use of microwaves, an old technology with new enthusiasts behind it, supposedly would generate higher EROIs but there have been studies of this yet in actually field conditions.

Meta-analysis of Oil Shale EROI Studies

Author	Date	Technique	Resource	System Boundary	EROI	Env. Issues
Legislative PO and NG Caucus	2007	-	Green/White Rivers, US	-	3	
Brandt, A.R.	2007	ATP retort, low case; high case	Green River, US	LCA; I/O; NER	2.5; 1.9	GHG
DOE	2006	surface; in situ non-electric; insitu electric	US	-	>10; 6.9; 2.5	
Lavelle, M.	2006	ICP	Green River, US	-	3	
Penner, S.S.	2006	in situ recovery	-	-	1.2-1.4	
Brandt, A.R.	2006	ICP small; ICP large; M&R	Green River, US	Primary E & materials	1.5; 4; <1.5	GHG
Cleveland, C.J.	2005	-	-	-	<5	
Committee on Resources	2005	ICP; ICP nat gas recycl	Green River, US	-	3; 6	GHG
Cleveland, C.J. et al.	1984	-	-	-	0.7-13.3	
Marland, G., et al*	1978	M&R minus refining	-	-	8.6	
Gardner, G.M.*	1977	M&R	-	-	13.3	
Ireson**	1976	M&R	-	-	19.7	
Ceri**	1976	M&R	-	-	6.88	
Oregon Study**	1976	M&R	-	-	1.42	
Applied Systems Corp.**	1975	M&R	-	-	0.68	
Frabetti, A.J.*	1975	M&R	-	-	1.42	
Clark, C.E. and D.C. Varisco*	1975	M&R	-	-	7.62	

* Citation available in accompanying bibliography

** Taken from: Hall, C.A.S., C.J. Cleveland, and R. Kaufmann. 1986. *Energy and Resource Quality: The Ecology of the Economic Process*. John Wiley & Sons, Inc. 1986: p221-228.

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Socioeconomics

The useful oil that is obtained from retorting oil shale is synthetic crude which, like petroleum crude oil, requires refining to produce transportation fuels, heating oil, asphalt, and other

petrochemicals. It can also be burned directly as a low-grade fuel for use in electric power plants, or in the manufacture of cement (Cleveland 2004).

The economics of shale oil production are largely dependent on the methods used. For example, cost per barrel of oil production/retorting is \$8 USD when utilizing purchased electrical heat. However, it decreases to \$4 USD per barrel when using cogenerated heat. This cost considers only retorting and does not consider mining. Mining costs range from \$6-22 USD per ton depending on the development stage of the mine and the type of equipment utilized. Accordingly, OT's technology and processes can produce one barrel of shale oil at approximately \$9.60 USD per barrel in the best case scenario and approximately \$30 USD per barrel in the worst case scenario (Ibid). The calorific value of oil shale is very low - 8.8 MJ/kg if compared to other fuels (18–30 MJ/kg for coal, 19 MJ/kg for wood and 45 MJ/kg for light crude) (Talve and Riipulk 2001). The energy content of the final product however is similar to crude oil. A problem that is obvious from the data is that shale oil is always waiting for oil to reach a given price level at which point it will become economic. But as that price is reached and surpassed (even over time by a factor of ten) it remains uncompetitive because the cost of the extraction and processing has increased (Hall et al. 1986). The problem here as with many other alternatives to what we do today, is that as the price of oil (or fossil fuels more generally increases so does the price of everything made directly or indirectly with oil, which is essentially everything from steel to chemicals to water to labor.

In the U.S., a large-scale commercial oil shale operation could have a significant impact on any nearby communities, the extent of which depends on the existing infrastructures and many other factors. As such, in a case where shale oil development overlaps an area with increasing tourism and recreation opportunities and an expanding urban population, on top of this existing network of energy development and changing land uses it is likely to put much more pressure on an already fragile ecosystem and public temperament (Committee on Resources 2005). An important issue is that most oil shales exist in areas very far from any infrastructure (housing, water, schools and so on) so that either very large daily transportation would be needed or whole new towns would need to be constructed.

At one time the prospects for oil shale in Australia seemed rather bright, and in the same issue (March 1998) of Scientific American that published the important paper "The end of cheap oil" by Colin Campbell and Jean Laherrere they also published, almost as an antidote, the optimistic "Mining for oil" by Richard George, head of the Suncor Corporation. George wanted to apply the Canadian tar sands technique, operational at that time, to oil shale. He wrote "a whole new oil shale industry could develop in Australia over the next decade. So as production from conventional oil fields dwindles, oil shale and oil sand reserves may well become a major source of energy in the century to come. According to Laherrere (personal communication) "It is obvious that George combines in the same article thinking on 'oil sands' and 'oil shales.' Although both are commonly mined and need to be heated in giant drums, they have completely different origin and expulsion. Bitumen (oil sands) are mainly degraded oil fields, as the end of the process before being completely eroded while oil shales are immature source-rock where oil has not yet been generated. They require pyrolysis at over 500°C to generate oil: there is no way that you can do it in a washing machine as Clark did it in 1920 for oil sands where you need only temperature well below 100°C. The economics are also quite different. It should be stated that there are very different birds! And although Suncor spent \$150 M to build the retorting plant in Australia they dropped the plant and wrote off their investment after failing to get a steady phase 1 production level of 4000 b/d. Their Australian partners were bankrupted, and the project has been idle since

2004! Mining oil shale is recognized as a poor project now and the goal is in situ pyrolysis by heating the source material with electric heaters while freezing the material around the material being heated to prevent the polluted water to leave. But Shell will not decide before 2012 if they will build a commercial pilot. The USDOE is forecasting no oil shale production before 2030.”

Environment

At present, the environmental impacts of shale oil production seem large. Oil shale is usually mined and so there are surface impacts; however, the Shell ICP process may be able to reduce surface impacts by up to a factor of ten (US DOE ONPOS. 2004). Production is water intensive, which is an important limited resource in the dry U.S. regions with large oil shale deposits (Committee on Resources 2005; Veil and Puder 2006). It is thought to require 1 or 2 barrels of water for every barrel of oil produced, where two-thirds of that water is dedicated to human resources, supporting people and infrastructure around production (Committee on Resources 2005; US DOE ONPOS. 2004).

The retorting processes are energy-intensive and there are also combustion emissions in areas where the air is currently very clean (Ibid). The mining or in situ technologies also disturb the local water tables. In the case of the in situ technology, the spent shale in place may contain toxins that need to be kept away from ground water; however, Shell has developed a “freeze wall” (maintained with in situ freezers running on electricity) designed to isolate the process from local ground water (Ibid). In the case of surface retorting, the spent shale, processing water, and other byproducts must be disposed of in a safe manner.

The spent shale represents a particular problem because it takes up considerably more volume than the original rock, up to 30% more (US DOE ONPOS. 2004), and therefore affords a greater opportunity for infiltration by both precipitation and groundwater (Veil and Pruder 2006). How to achieve disposal on a massive scale has not been defined (Committee on Resources 2005). Furthermore, in the case of the Colorado River watershed, salinity is a major concern and eliminating it is one of the key goals of the Bureau of Reclamation, however, oil shale production would contribute to increased salinity (Veil and Pruder 2006).

Assuming fossil fuels are used to provide the energy input for shale oil production, the net greenhouse gas impact of developing oil shale resources can also be assumed to be substantially higher than the per-unit impact of conventional oil production. Brandt found that the Shell ICP production process has GHG emissions that are similar to those from tar sands production in Alberta; and that the mining and retorting process has emissions significantly in excess of synthetic fuels produced from coal and over 4 times the emissions from conventional oil (Table 2).

Table 7: Emissions estimates from this study compared to other estimates of emissions (gCeq./MJ of refined product). L = Low estimate or low case, H = High estimate or high case. Totals may not sum exactly due to independent rounding.

	Brandt - L	Brandt - H	OSEC ^a	Sundquist - L ^b	Sundquist - H ^c	Burnham - HRS ^d	Greenpeace ^e
Upstream (gCeq./MJ)	14.6	17.6	20.5	10.8	53.9	9.2	12.0
Refining (gCeq./MJ)	2.6	2.9	2.9	2.9	2.9	2.9	2.9
Combustion (gCeq./MJ)	18.2	20.2	20.3	20.3	20.3	20.3	20.3
Total (gCeq./MJ)	35.3	40.8	43.7	34.0	77.1	32.4	35.3

a - These figures are directly from OSEC EIS for Phase 3 of the project [29, p. 104]. Because OSEC figures are for upgraded shale oil, refining emissions were added from Brandt (high case), and refining conversion efficiencies were applied to upstream emissions to convert to emissions per MJ of final fuel. The Brandt low case is not used because refinery emissions are per unit FFD and FFD in the low case includes natural gas and waste heat co-products in sizeable quantities.

b - This figure is for low-temperature retorting of 25 gal/ton shale [41]. The original estimate only includes retorting and combustion of raw oil; construction, mining, refining, and marketing are not included [41, p. 740]. Upstream mining and preparation emissions from Brandt (high case) are added to upstream figure. Upstream emissions are adjusted for refining efficiency as in note *a*. Refining emissions are added as in note *a*.

c - Figure for high-temperature retorting of 25 gallon/ton shale [41], assuming complete carbonate decomposition and complete combustion of organic matter. This represents an *extreme upper bound* for emissions from 25 gal/ton shale. Adjustments are made as in note *b*.

d - Figure is believed to be for the LLNL HRS process on 25 gal/ton shale [9]. No upstream mining or preparation emissions are included, so these are added as in note *b*. Refining adjustments are made as in note *a*.

e - Figure for retorting of Australian Stuart oil shales in the SPP ATP retort [20]. Refining adjustments are made as in note *a*. A detailed breakdown of emissions sources [20, p. 39] does not include carbonate decomposition. This is because Australian Stuart oil shale deposits are different in character than Green River shales, having clay minerals that affect enthalpy below 500 °C [5] but having much lower carbonate mineral content (7% calcite, no dolomite)[4].

Table 2(from Brandt 2007).

Click to Enlarge.

According to Brandt, if shale oil is produced, refined, and combusted at a rate equal to 10% of 2005 U.S. gasoline consumption the full-fuel cycle emissions increase relative to conventional oil would be about 45 million tons of carbon to between 68 and 74 million tons of carbon (2007). Furthermore, it has been found that Estonian oil shale extraction causes surface subsidence when mining activities cease which leads to the formation of bogs, rendering agricultural areas unusable, and the death of forests (Talve and Riipulk 2001). Other concerns include sulfur-gas emissions, high CO₂ release per barrel of oil for modified in-situ processing, disturbance of topography, water consumption, and degradation of ground-water quality due to mobilization of organics and inorganics in the spent shale. Such environmental concerns played a major role in the death of the U.S. federal oil shale research program in 1994 (Burnham 2003).

CONCLUSION

In conclusion, although shale oils represent a huge potential resource they have a history of “always a bridesmaid and never a bride” because as prices for oil increase the prices for extracting shale oil have increased as well. This history represents the very real problems of generating a useful product from the resource. The main problems include the distance of the shale from both the water and labor needed to extract it, the large environmental impact compared to conventional oil and the relatively low EROI. In addition, with both shale and tar sands there is some disagreement whether the in situ should be charged as an energy opportunity cost, (in the same sense that bagasse could be in sugar cane ethanol). Ultimately, the question is, if conventional oil becomes very scarce whether a resource such as shale oil will be developed regardless of cost.

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