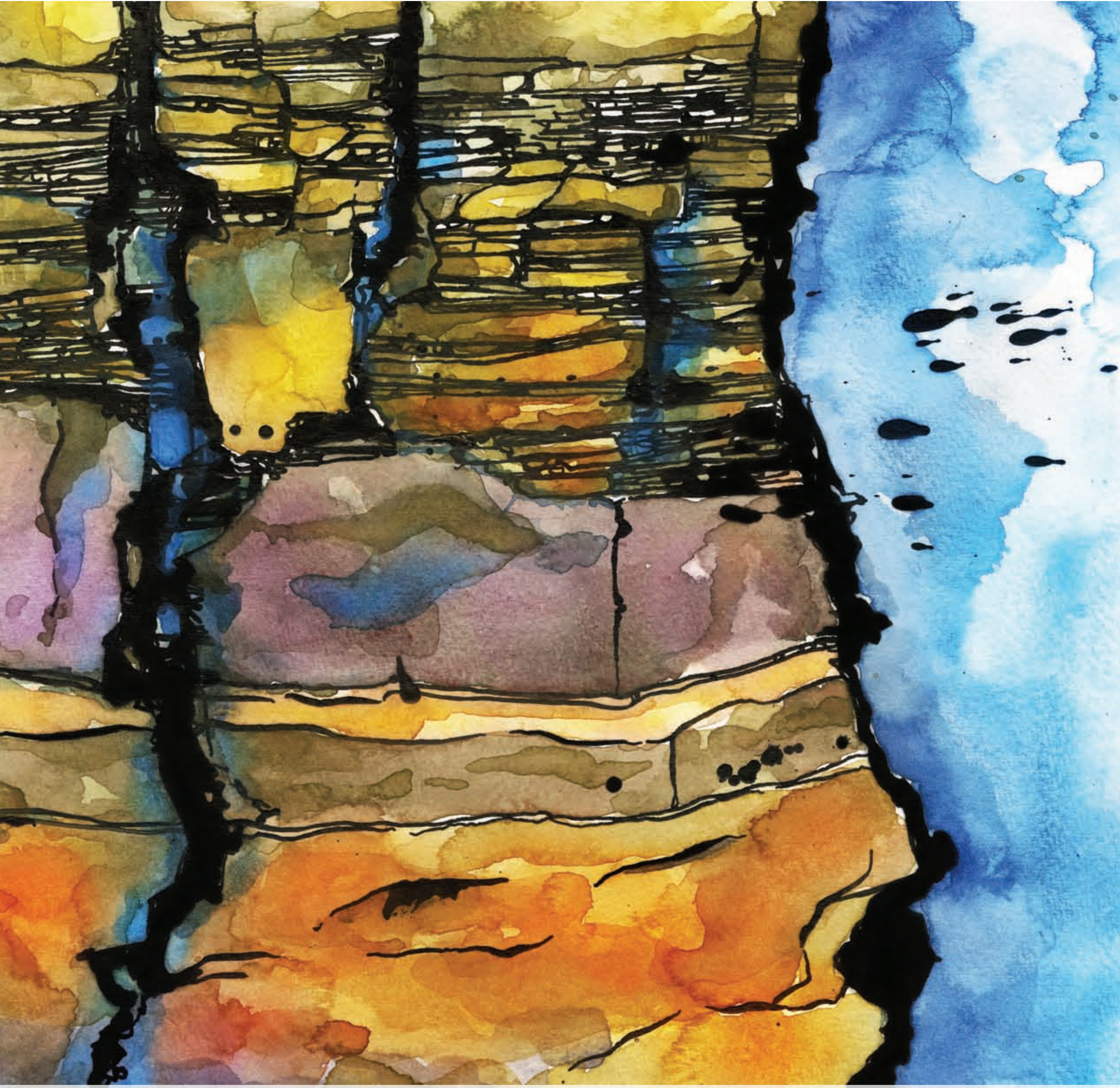

A Market Assessment of Oil Shale and Oil Sands Development Scenarios in Utah's Uinta Basin

Prepared by the Institute for Clean and Secure Energy

The University of Utah

Disclaimer

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List of Acronyms

η	Extraction efficiency of bitumen/sand separation process in Equation (8.1)
θ	Down-dip angle in Equation (8.1)
ρ	Density in Equation (8.3)
ρ_{bit}	Bitumen density in Equation (8.1)
ρ_{ore}	Oil sand density in Equation (8.1)
a	Constant in Equations (6.1) & (6.2)/Stoiciometric coefficient in Equation (6.3)
AEO	Annual Energy Outlook
AMSO	American Shale Oil
API	American Petroleum Institute
ATP	Alberta Taciuk Process
b	Constant in Equations (6.1) & (6.2)/Stoichiometric coefficient in Equation (6.3)
B	Bitumen production rate in Equation (8.1)
BLM	Bureau of Land Management
C	Tax credit in Equation (3.3)/Cost in Equations (5.5) & (6.2)
C$	Canadian dollars
CAA	Clean Air Act
C_{alloc}	Allocated costs for utility plants
capex	Capital expenditure
CARB	California Air Resources Board
C_{BM}	Bare module cost in Equation (5.6)
CCI	Construction Cost Index
CCS	Carbon capture and storage

C_{cont}	Costs for contingencies and contractor fees
C_{DPI}	Total direct permanent investment
C_{drill}	Capital cost of drilling in Equation (5.1)
CEPCI	Chemical Engineering Plant Cost Index
CERA	Cambridge Energy Research Associates
CERI	Canadian Energy Research Institute
C_F	Fixed costs
CF	Annual cash flow in Equations (5.1) & (5.3)
CH_4	Methane
C_L	Cost of mineral leases and land acquisition for production facilities
CN	Cetane number
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	CO_2 equivalent
COM	Cost of manufacture in Equation (5.8)
C_P	Cost of permitting in Equation (5.1)/Purchase cost of piece of equipment in Equation (5.6)
CPF	Central processing facility
CPFB	Cost per flowing barrel
C_{pipe}	Cost of pipelines
C_{rec}	Cost of well reclamation in Equation (5.1)
C_{RIP}	Cost of intellectual property royalties
C_S	Cost of plant startup
C_{site}	Cost of site preparation

C_{resv}	Cost for water reservoir
C_{serv}	Cost of service facilities
C_{TBM}	Total bare module investment
C_{TCI}	Total capital investment
C_{TDC}	Total depreciable capital
C_{TPI}	Total permanent investment
C_V	Variable costs
C_{WC}	Working capital
d	Depletion in Equation (5.13)
D	Depreciation in Equations (5.8) & (5.13)/Direct requirements table
DEA	Diethanol amine
DOE	Department of Energy
DOGM	Division of Oil, Gas, and Mining
DOI	Department of Interior
DOT	Department of Transportation
EIA	Energy Information Administration
ENR	Engineering News Record
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EROI	Energy returned on invested
ESA	Endangered Species Act
f	Discount factor in Equations (5.2) & (5.3)
F_{bm}	Bare-module factor in Equation (5.6)

F_d	Equipment design factor in Equation (5.6)
F_{ISF}	Investment site factor
FLPMA	Federal Land Policy and Management Act
F_m	Material factor in Equation (5.6)
f.o.b.	Free on board
F_p	Pressure factor in Equation (5.6)
f_{ST}	Fraction used in computing severance tax in Equation (5.12)
GAO	Government Accountability Office
GDP	Gross domestic product
GHG	Greenhouse gas
GOSSR	Generic Oil Sands Royalty Regime
GSP	Gross state product
GWSA	Global Warming Solutions Act
H	Deposit thickness in Equation (8.1)/Hydrogen
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
HCI	RS Means Historical Cost Index
HO	Heavy Oil
I	Personal income tax liability in Equation (3.3)/Generic cost index in Equations (5.5) & (5.6)
ICP	In-situ Conversion Process
ICSE	Institute for Clean and Secure Energy
IO	Input-output

IRR	Investor's rate of return
L	Length of oil sands mine in Equation (8.1)
LCFS	Low-carbon fuel standards
LHV	Lower heating value
LO	Light oil
LS	Operations salary and benefits
LW	Operations wages and benefits
m	Scaling power in Equations (5.5) & (5.7)/Mass of H_2 required per barrel of oil in Equation (8.2)
M	Maintenance
MARCS	Modified Accelerated Cost Recovery System
MCI	Material Cost Index
M_i	Molecular weight of species i in Equations (8.3)–(8.5)
MI	Mineral insulated
MS	Maintenance salary and benefits
MW	Maintenance wages and benefits
NAICS	North American Industry Classification System
NEPA	National Environmental Policy Act
n	Year of the project in Equations (5.1)–(5.3)
N	Nitrogen
N_2O	Nitrous oxide
NFRCI	Nelson-Farrar Refinery Construction Index
NH_3	Ammonia
NI	Nickel

NPV	Net present value
NSURM	National Strategic Unconventional Resource Model
o	Subscript referring to base value/Subscript referring to hydrotreater feed in Equations (8.3)–(8.5)
O_2	Oxygen
OOIP	Original oil in place
opex	Operating expenditure
OSEC	Oil Shale Exploration Company
OSR	Oil Sands Royalty
OTA	Office of Technology Assessment
P	Production capacity in Equation (5.1)
PADD	Petroleum Administration Defense District
PEIS	Programmatic Environmental Impact Statement
PPI	Producer's Price Index
PSA	Pressure swing adsorption
p_t	Depletion factor in Equation (5.14)
Q	Material capacity in Equations (5.5) & (5.7)
r	Credit rate in Equation (3.3)/Royalty rate in Equation (5.9)
R	Royalties on oil production in Equation (5.11)
r_{cf}	Conservation fee in Equation (5.12)
r_d	Desired annual discount rate in Equation (5.2)
RD&D	Research, Development and Demonstration
RFG	Recycled flue gas
R_{IP}	Royalties for intellectual properties

ROR	**Rate of return**
r_{ST}	**Severance tax rate in Equation (5.12)**
S	**Sulfur/Total gross sales per year at full production capacity in Equations (5.1) & (5.13)**
S_a	**State corporate income tax liability after credit in Equation (3.4)**
S_b	**State corporate income tax liability before tax credit in Equations (3.3) & (3.4)**
SAGD	**Steam Assisted Gravity Drainage**
SCO	**Synthetic crude oil**
SIP	**State Implementation Plan**
SITLA	**School and Institutional Trust Lands Administration (Utah)**
SO_2	**Sulfur dioxide**
S_{oil}	**Oil sales for a given year in Equation (5.9)**
SOR	**Steam to oil ratio**
SR	**Stripping ratio**
SR_{max}	**Maximum stripping ratio that mine will reach in Equation (8.1)**
ST	**Severance tax in Equation (5.12)**
STSA	**Special Tar Sands Area**
t	**Time that mine is in operation in Equation (8.1)**
T	**Total tax liability in Equation (5.17)**
TBP	**True boiling point**
t_F	**Federal corporate tax rate in Equation (5.16)**
T_F	**Federal corporate income tax in Equation (5.16)**
TI	**Taxable income in Equation (5.13)**
t_S	**State corporate tax rate in Equation (5.15)**

T_S	State corporate income tax in Equation (5.15)
TV	Taxable value in Equation (5.11)
U	Utah sales tax revenue in Equation (3.3)/Utility requirement in Equation (5.7)
UDAQ	Utah Division of Air Quality
UGS	Utah Geological Survey
US$	U.S. dollars
USGS	United States Geological Survey
V	Vanadium
VGO	Vacuum gas oil
VPO	Vapor pressure osmometry
WTI	West Texas Intermediate
WTP	Well-to-pump
WTW	Well-to-wheel
WV	Wellhead value in Equation (5.10)
x	Bitumen saturation in Equation (8.1)
X	Oil production capacity in Equation (6.2)
x_i	Mass fraction of species i in Equations (8.3)–(8.5)

List of Units

%	Percent
/bbl	Per barrel
/ft	Per foot
/ton	Per ton
/yr	Per year
bbl/bbl of oil	Barrel per barrel of oil
BPD	Barrels per day
Btu	British thermal units
Btu/lb	British thermal units per pound
°C	Degrees Celcius
CFS	Cubic feet per second
CMS	Cubic meters per second
cP	Centipoise
°F	Degrees Farenheit
ft	Feet
g	Grams
g/cc	Grams per cubic centimeter
g CO_2e/MJ	Grams of CO_2 equivalent per megajoule of energy released
g/hp-hr	Grams per horsepower per hour
GJ	Gigajoule
GJ/bbl	Gigajoules per barrel
gpm	Gallons per minute

GPT	Gallons per ton
GW	Gigawatt
kg/m^3	Kilograms per cubic meter
kgal	Thousand gallons
klb	Thousand pounds
km	Kilometers
kPa	Kilopascals
kPag	Kilopascals gauge
kW	Kilowatt
kWh	Kilowatt-hour
lb/ft^3	Pounds per cubic foot
lb/hr	Pounds per hour
m	Meters
mD	Millidarcies
mm	Millimeters
MMBtu	Million British thermal units
MPG	Miles per gallon
MW	Megawatt
MTPD	Metric tons per day
ppb	Parts per billion
ppm	Parts per million
psi	Pounds per square inch
psig	Pounds per square inch (gauge pressure)

SCF	**Standard cubic feet**
SCFM	**Standard cubic feet per minute**
sec	**Second**
TPD	**Tons per day**
vol%	**Volume percent**
W/ft	**Watts per foot**
W/m	**Watts per meter**
wt%	**Weight percent**

Executive Summary

The enormous size of U.S. oil shale and oil sands resources, and Utah resources in particular, is well-known. Recent analyses by the United States Geological Survey of oil shale resources in western Colorado and eastern Utah have estimated the total in-place oil in the Piceance Basin of Colorado at 1.53 trillion barrels [1] and in the Uinta Basin of Utah at 1.32 trillion barrels [2]. A 2008 Utah Geological Survey study estimates the economically-recoverable resource in the Uinta Basin to be 77 billion barrels [3]. The total U.S. oil sands resource is estimated at 76 billion barrels of in-place oil. The largest U.S. oil sands deposits are found in the State of Utah, which has an estimated resource size of 32 billion barrels of in-place oil [4]. A 2013 study of a large Utah deposit known as Tar Sand Triangle estimates a commercially viable resource size of 1.30–2.46 billion barrels in that deposit [5]. Despite the size of the resource and the fact that U.S. production of liquid transportation fuels from oil sands and oil shale has been shown to be technically feasible [1–3], there is currently no commercial scale production of either resource.

Purpose of Assessment

Given today's economic and political climate, this report seeks to assess significant impediments to and impacts of development of U.S. oil shale and oil sands resources. It focuses on three specific questions: (1) what positive and negative externalities and non-market costs are associated with development of these resources and how does the perception of these costs impact development; (2) what is the per barrel cost of oil produced from four oil shale and oil sands development scenarios; and (3) what are the broad regional impacts that may result as side effects if the scenarios are realized.

Assessment Approach

This assessment is divided into ten sections.

Sections 1–3. The first three sections provide background material to better understand the economic analysis that follows. Section 1 focuses on the impact of U.S. energy policy and rising public concern about anthropogenic climate change on oil shale and oil sands development. Section 1 also reviews past evaluations of commercial unconventional fuels development and outlines the scope of the study. Section 2 reviews what is known about oil shale and oil sands resources in the Uinta Basin of Utah. Section 3 examines the set of rules concerning how local, state, and federal government revenue would be derived from the production of oil from oil sands and oil shale. Collectively, this set of rules is known as "fiscal policy."

Section 4. This section reviews the concept of externalities and explores four commonly cited externalities related to oil shale and oil sands development: water resources and availability, land use impacts, air quality, and carbon management.

Sections 5–9. Section 5 outlines the cost estimating methodologies used to determine the economic viability of four unconventional fuel development scenarios in Utah's Uinta Basin. These scenarios (Sections 6–9) are:

- Ex situ extraction (underground mining, surface retorting) of oil shale
- In situ extraction (underground heating) of oil shale
- Ex situ extraction (surface mining, surface processing) of oil sands
- In situ extraction (Steam-Assisted Gravity Drainage) of oil sands.

The production capacity of the two oil shale scenarios is set at 50,000 barrels per day (BPD) while the production capacity of the two oil sands scenarios is 10,000 BPD. All scenarios are assumed to start in 2012 and end in 2035, with four years for design and construction and 20 years for production. The scenarios encompass extraction with the subsequent upgrading of the extracted product (raw shale oil and bitumen) to make a light, low-sulfur synthetic crude oil that is pipelined from the point of upgrading to North Salt Lake City, Utah, refineries. Each scenario includes a detailed description of the process components, an estimate of process inputs and outputs such as water requirements and CO_2 emissions, a capital cost estimate, a supply price analysis for a "base case" set of assumptions (including a detailed price breakdown), a supply price evaluation of raw product (i.e. no upgrading), a net present value analysis using oil price projections from the U.S. Energy Information Administration (EIA) [6], and a sensitivity analysis that examines the effect of various parameter values on the computed supply price of oil. In addition, a carbon management scheme that involves using oxygen rather than air for all combustion processes is analyzed.

Section 10. This section reports results from an input-output analysis of the potential economic impacts arising from successful ex situ oil shale or oil sands projects in the Uinta Basin.

Key Results

All of the projects will require extensive capital investment with "base case" capital costs ranging from $800 million for a 10,000 BPD oil sands production facility to $6 billion for a 50,000 BPD in situ oil shale production facility.

Assuming that investors require a minimum rate of return of 10% and that prices for a West Texas Intermediate (WTI)-quality crude oil follow the EIA reference forecast to 2035 [6], both the 50,000 BPD ex situ oil shale and the 10,000 BPD ex situ oil sands scenarios ("base cases") are profitable. If investors are willing to accept a slightly lower rate of return (9%), then the "base case" 10,000 BPD in situ oil sands scenario is profitable as well. The "base case" 50,000 BPD in situ oil shale scenario is not profitable given the crude oil reference forecast price.

The economic impacts to the State of Utah associated with 20-year operations phase of a 50,000 BPD ex situ oil shale facility are based on the assumption that 50% of total expenditures are spent somewhere in the state. Depending on the technology used, the $5.87–$6.27 billion assumed spent on Utah-based suppliers generates an additional $10.4–$11.0 billion in business sales, $2.25–$2.50 billion of additional wage earnings associated with 50,500–59,000 person-years of employment, and $5.85–$6.20 billion of gross state product (GSP) in Utah. The $1.53 billion assumed spent on Utah-based suppliers during the 20-year operations phase of a 10,000 BPD ex situ oil sands facility generates an additional $2.75 billion in business sales, $622 million of wage earnings associated with approximately 15,000 person-years of employment, and $1.50 billion of GSP.

Externalities

Diverse public costs, or externalities, are associated with development of oil shale and oil sands. One positive externality that is used as an argument for development is the increase in energy security resulting from increased domestic production. However, the impact on energy security of the scenarios analyzed in this study would be limited because: (1) a 50,000 BPD production level represents about one-quarter of 1% of U.S. petroleum consumption and (2) if such production did have an impact on oil prices, which are determined in an integrated global market, it is also likely to increase oil consumption. Another oft-cited positive externality, that such activity will benefit the U.S. in terms of job opportunities and private and public revenue, depends on the particular state of the economy during the time of production. To the extent that capital and other resources are fully employed in other activities during the course of development, they are shifted from one activity to another. When unemployment rates are high, the value of forgone opportunities is low and much of the gross gain in employing labor, capital, and resources in the new industry is net gain.

Given the arid environment of the Uinta Basin, water resources and availability are frequently mentioned as negative externalities associated with development. While the financial cost of water is readily addressed in economic models, water acquisition represents an externality because water supplies are finite and water rights reallocations can impact the quality of life in rural communities and environmental values. Opposition to reallocation has the potential to increase transaction and permitting costs. The specifics of the water challenges associated with obtaining water for oil shale or oil sands development will depend upon how industries develop and whether such development supplants or supplements other water uses.

Land use also represents an externality as development of oil shale and oil sands may render land incompatible for previous or planned uses during the time period of production and reclamation. Opposition to shifts in land use for large tracts of land can impact permitting costs. The Endangered Species Act presents additional land use challenges for development given that Uintah County, situated in the Uinta Basin, is home to nine federally-listed or candidate animal species and other species with special designations [7]. Additionally, the most prospective oil shale area is home to several federally protected or candidate plant species.

Reduced air quality from industrial development represents a negative externality for those living in the Uinta Basin airshed. Degraded ambient conditions in the Uinta Basin pose a serious challenge to any development proposal that further reduces air quality. A related concern is whether the U.S. Environmental Protection Agency, which has primary regulatory jurisdiction over Indian Country (where 72% of oil and gas production in the Uinta Basin occurs [8]), has the local knowledge and flexibility needed to craft innovative response strategies that protect local economic interests.

The externalities associated with carbon management hinder both energy policy and energy resource development. For oil shale and oil sands, the raw material extraction, processing, and upgrading life-cycle stages can be important contributors to the carbon footprint. Given the uncertainty of the regulatory climate with respect to carbon, two different combustion systems are considered to supply heat for the various scenarios. In the conventional system, natural gas is combusted with air and the resulting combustion gases are sent to a stack. For the profitability analysis, two cases are considered: (1) no tax on CO_2 and (2) a $25 per ton tax on CO_2. In the oxy-combustion system, natural gas is combusted with a mixture of oxygen and recycled flue gas (mainly CO_2 and water). After processing, a nearly pure CO_2 stream remains that can be sold for enhanced oil recovery or sequestered.

Ex Situ Oil Shale Scenario

This scenario is located in the northeast section of the Uinta Basin, the most promising area for development as it corresponds to the basin depocenter. The oil shale is mined underground and processed in a surface retort to extract the raw shale oil. Two retorting technologies were selected for this report, Tosco II and Paraho Direct. The raw shale oil undergoes an upgrading step (hydrotreating) such that the finished product is a WTI-quality synthetic crude oil. The finished product is then pipelined to North Salt Lake City, Utah, refineries. Two methods of assessing profitability are employed. The Supply Price Method finds the minimum price of oil that ensures profitability of the project if that price, adjusted for inflation, were received on each barrel of oil sold from the project. The Net Present Value Method evaluates the profitability of the project when the oil prices received are those of the most recent EIA oil price forecasts.

Table 1 lists the major outputs from and inputs to ex situ production of synthetic crude oil from oil shale on a per barrel basis. The production of CO_2 is greater for the Paraho Direct process than for the Tosco II process because the high temperature in the Paraho Direct retort leads to formation of CO_2 from carbonate decomposition; CO_2 emissions from carbonate decomposition in the the Tosco II retort are assumed to be negligible. The CO_2 from the oxy-fired scenario is captured and of pipeline-quality that can be sold; CO_2 from the air-fired scenario is dilute and is emitted into the atmosphere from a smokestack.

Table 1. Major process outputs and inputs on a per barrel basis for ex situ oil shale scenario.

Category	Item	Tosco II Air-Fired	Tosco II Oxy-Fired	Paraho Air-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	20.94	20.94	20.94	lb
	CO_2 [a]				
	Emitted to Atmosphere	544	191	833	lb
	Sold to Pipeline	-	421	-	lb
	Spent Shale	41.69	41.69	42.02	ft^3
	Steam (600 psig, 700°F)	396	396	396	lb
	Sulfur	1.96	1.96	1.96	lb
Inputs	Catalyst	0.02	0.02	0.02	lb
	Electricity	14.31	35.96	88.77	kWh
	Fuel [b]				
	Purchased	1.19	1.16	1.93	MMBtu
	Total	3.84	3.80	3.01	MMBtu
	Makeup Water	6.28	6.32	3.00	bbl
	O_2	-	396	-	lb
	Refrigerant	2.72	2.72	2.72	MJ
	Steam				
	50 psig	433	433	250	lb
	450 psig	77	77	184	lb

[a] The per barrel CO_2 output is CO_2 equivalent (CO_2e). These emissions do not include those associated with facilities construction, refrigeration, and water treatment.
[b] The fuel input refers to natural gas only.

The total capital investment for the complete Tosco II air-fired plant is $5.941 billion; that of the Tosco II oxy-fired plant is $6.192 billion. The total capital investment for the Paraho Direct air-fired plant is almost 20% lower at $4.789 billion. A capital cost breakdown is available in the report.

Base case supply prices as a function of hurdle rate are given in Table 2 for Tosco II air-fired combustion and in Table 3 for Paraho Direct air-fired combustion. The hurdle rate is the minimum rate of return that an investor requires before investing his/her funds in the project; it is the opportunity cost of capital [9]. All supply costs listed in the tables are positive contributors to the supply price while all non-oil revenue streams are negative contributors.

Table 2. Supply price for Tosco II air-fired ex situ oil shale production scenario as a function of hurdle rate. Footnotes also apply to Table 3.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine [a]	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79
Retort	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36
Upgrading [b]	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14
Taxes	$ 10.73	$ 13.33	$ 16.61	$ 20.37	$ 24.62	$ 29.79	$ 35.77
Oil Royalties	$ 8.30	$ 9.19	$ 10.25	$ 11.47	$ 12.84	$ 14.45	$ 16.28
Net Earnings	$ -	$ 4.69	$ 10.16	$ 16.43	$ 23.51	$ 31.61	$ 40.75
Maintenance	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65
Other [c]	$ 14.81	$ 14.86	$ 14.93	$ 15.01	$ 15.10	$ 15.20	$ 15.31
Supply Cost	**$ 78.79**	**$ 87.02**	**$ 96.90**	**$ 108.23**	**$ 121.02**	**$ 135.99**	**$ 153.06**
Other Revenue	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47
Oil Supply Price	**$ 77.32**	**$ 85.56**	**$ 95.43**	**$ 106.76**	**$ 119.55**	**$ 134.52**	**$ 151.60**

[a] "Mine" includes costs for mining and size reduction/solids handling (e.g. crushing).
[b] "Upgrading" includes all costs associated with the fractionator, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.
[c] "Other" includes all costs associated with the oil pipeline, water pipeline, allocated costs for utility plants, water reservoir, site preparation, service facilities, contingency, permitting, research, administration, incentive compensation, insurance, intellectual property royalties, overhead, land, startup, and CO_2 compressor (oxy-firing only).

Table 3. Supply price for Paraho Direct air-fired ex situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32
Retort	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12
Upgrading	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41
Taxes	$ 8.84	$ 10.97	$ 13.61	$ 16.64	$ 20.07	$ 24.24	$ 29.05
Oil Royalties	$ 8.42	$ 9.14	$ 9.99	$ 10.97	$ 12.08	$ 13.37	$ 14.84
Net Earnings	$ -	$ 3.79	$ 8.19	$ 13.24	$ 18.94	$ 25.44	$ 32.78
Maintenance	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87
Other	$ 12.87	$ 12.92	$ 12.98	$ 13.04	$ 13.11	$ 13.19	$ 13.28
Supply Cost	**$ 79.85**	**$ 86.53**	**$ 94.49**	**$ 103.60**	**$ 113.91**	**$ 125.95**	**$ 139.67**
Other Revenue	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47
Oil Supply Price	**$ 78.38**	**$ 85.06**	**$ 93.02**	**$ 102.13**	**$ 112.44**	**$ 124.48**	**$ 138.20**

Detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters are included in the report.

In Situ Oil Shale Scenario

The scenario is located near Bonanza, Utah, across the White River from the ex situ oil shale scenario. In situ production occurs by underground heating to extract oil from the oil shale followed by pumping of the produced oil to the surface and upgrading. The upgraded product is then pipelined to North Salt Lake City, Utah, and sold to a refinery. The design production capacity is 50,000 BPD, but this production volume is only achieved in the final years of the 24-year project due to the long time delay between the initiation of underground heating and the maximum production rate. This scenario is developed using commercially-available reservoir simulation tools and equipment that can be purchased "off-the-shelf" and does not necessarily represent what might be achievable using technologies currently under development.

Table 4 lists the major outputs from and inputs to this in situ oil shale production scenario on a per barrel basis. The CO_2 emissions are nearly double those of ex situ production (Tosco II, air-fired) due to the energy requirements of heating the resource underground and the long time lag from the initiation of heating to the start of significant production.

Table 4. Major process outputs and inputs on a per barrel basis for in situ oil shale scenario.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	9.64	9.64	lb
	CO_2 [a]			
	Emitted to Atmosphere	1,060	1,016	lb
	Sold to Pipeline	-	59	lb
	Steam (600 psig, 700°F)	25	25	lb
	Sulfur	2.09	2.09	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	10.68	14.78	kWh
	Fuel [b]			
	Purchased	6.44	6.44	MMBtu
	Total	7.01	7.00	MMBtu
	Makeup Water [c]	0.74	0.74	bbl
	O_2	-	72	lb
	Refrigerant	2.72	2.72	MJ
	Steam			
	50 psig	266	266	lb
	450 psig	77	77	lb

[a] *The per barrel CO_2 output is CO_2e. These emissions do not include those associated with facilities construction, refrigeration, water treatment or in situ decomposition of carbonate minerals in the oil shale.*
[b] *Same as Table 1, footnote "b."*
[c] *The makeup water includes the water required for drilling. If the water for drilling is excluded, makeup water is 0.09 bbl/bbl of oil.*

The total capital investment for the complete air-fired production facility is $6.02 billion and for the oxy-fired facility is $6.08 billion. A breakdown of all capital costs is available in the report; the largest capital cost (48% of the total) is for drilling.

Base case supply prices for air-fired in situ oil shale production for hurdle rates up to 6% are given in Table 5. Due to the high supply prices associated with this scenario, additional hurdle rates were not investigated.

Table 5. Supply price for air-fired in situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%
Drilling	$ 23.00	$ 23.00	$ 23.00	$ 23.00
In Situ Retort [a]	$ 44.13	$ 44.13	$ 44.13	$ 44.13
Upgrading [b]	$ 12.42	$ 12.42	$ 12.42	$ 12.42
Taxes	$ 47.66	$ 61.05	$ 78.63	$ 101.92
Oil Royalties	$ 22.05	$ 27.03	$ 33.42	$ 41.66
Net Earnings	$ -	$ 22.73	$ 51.47	$ 87.93
Maintenance	$ 14.72	$ 14.72	$ 14.72	$ 14.72
Other [c]	$ 19.41	$ 19.68	$ 20.04	$ 20.50
Supply Cost	**$ 183.39**	**$ 224.76**	**$ 277.82**	**$ 346.27**
Other Revenue	$ 0.18	$ 0.18	$ 0.18	$ 0.18
Oil Supply Price	**$ 183.21**	**$ 224.58**	**$ 277.64**	**$ 346.08**

[a] *"In Situ Retort" includes all costs associated with the natural-gas fired generators and the electrical heaters.*
[b] *Same as Table 2, footnote "b."*
[c] *Same as Table 2, footnote "c."*

The report also includes detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters.

Ex Situ Oil Sands Scenario

The location for this scenario is the Asphalt Ridge-Whiterocks Special Tar Sands Area (STSA) southwest of Vernal, Utah. The oil sands are mined from an outcrop on the Asphalt Ridge and then mining is assumed to proceed down-dip, following the deposit to the southwest. The mined material undergoes grinding, sand/oil separation in hydrocyclones using a hot water/solvent extraction process to extract bitumen, and primary and secondary upgrading of the bitumen. The synthetic crude oil that results is then pipelined to refineries in North Salt Lake City, Utah.

Table 6 lists the major outputs from and inputs to this ex situ oil sands production scenario on a per barrel basis. Water usage is similar to that for the Paraho Direct ex situ oil shale scenario and half that of the Tosco II ex situ oil shale scenario.

Table 6. Major process outputs and inputs on a per barrel basis for ex situ oil sands scenario.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	5.76	5.76	lb
	CO_2 [a]			
	Emitted to Atmosphere	253	150	lb
	Sold to Pipeline	-	152	lb
	Steam (600 psig, 700°F)	78	78	lb
	Petroleum Coke	46	46	lb
	Sulfur	0.85	0.85	lb
	Tailings [b]	9,274	9,274	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	17.89	25.42	kWh
	Fuel [c]			
	Purchased	0.91	0.89	MMBtu
	Total	1.39	1.38	MMBtu
	Makeup Water	2.80	2.81	bbl
	O_2	-	179	lb
	Refrigerant	13.58	13.58	MJ
	Solvent	0.16	0.16	gal
	Steam			
	50 psig	332	332	lb
	450 psig	383	383	lb

[a] *Same as Table 1, footnote "a."*
[b] *Tailings includes both overburden and wet sand. Quantity reported here is for the average stripping ratio of two.*
[c] *Same as Table 1, footnote "b."*

The total capital investment for the complete air-fired plant is $818 million; that of the oxy-fired plant is $848 million. The largest capital costs (air-fired) are for the hydrotreater (16% of total) and bitumen separation system (13% of total). The report contains a detailed breakdown of capital costs.

Table 7 lists base case supply prices as a function of hurdle rate for the air-fired ex situ oil sands scenario. The supply cost at a hurdle rate of 0% is the cost of the project without any investor profit.

Table 7. Supply price for air-fired ex situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine [a]	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31
Bitumen Recovery	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62
Upgrading [b]	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38
Taxes	$ 6.58	$ 8.20	$ 10.14	$ 12.42	$ 15.24	$ 18.51	$ 22.42
Oil Royalties	$ 8.02	$ 8.55	$ 9.18	$ 9.92	$ 10.80	$ 11.81	$ 13.01
Net Earnings	$ -	$ 2.77	$ 6.08	$ 9.97	$ 14.52	$ 19.74	$ 25.77
Maintenance	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17
Other [c]	$ 13.81	$ 13.85	$ 13.89	$ 13.94	$ 13.99	$ 14.06	$ 14.13
Supply Cost	**$ 76.90**	**$ 81.85**	**$ 87.78**	**$ 94.74**	**$ 103.05**	**$ 112.61**	**$ 123.82**
Other Revenue	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41
Oil Supply Price	**$ 75.50**	**$ 80.44**	**$ 86.37**	**$ 93.33**	**$ 101.65**	**$ 111.21**	**$ 122.42**

[a] "Mine" includes costs for mining and size reduction/solids handling (e.g. crushing).
[b] Upgrading" includes all costs associated with the delayed coker, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.
[c] Same as Table 2, footnote "c."

Included in the report are detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters.

In Situ Oil Sands Scenario

In this scenario, synthetic crude oil is produced from a Uinta Basin oil sand deposit using an in situ extraction process commonly employed in Alberta, Canada, Steam-Assisted Gravity Drainage (SAGD). The scenario is situated within the P.R. Spring STSA, 50 miles south of Vernal, Utah. Due to the lithological variability of the oil sand resource in the Uinta Basin in general and P.R. Spring in particular, it is not possible to model the SAGD process in the geologic setting of the P.R. Spring deposit. Instead, SAGD production costs for this scenario are based on information from a recent SAGD project in Alberta [10] and represents a best case "what-if" scenario were a producer to locate an oil sand deposit amenable to in situ development.

Table 8 lists the major outputs from and inputs to the in situ production of synthetic crude oil from oil sands on a per barrel basis. The CO_2 output (air-fired) is 60% higher than that from the ex situ oil sands scenario (air-fired) due to the CO_2 penalty of heating the ground with steam. The tradeoff is that because the bitumen is produced in situ, there is not a large waste stream of oil sand tailings as with the ex situ oil sands scenario.

Table 8. Major process outputs and inputs on a per barrel basis for in situ oil sands scenario.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	5.63	5.63	lb
	CO_2 [a]			
	Emitted to Atmosphere	409	324	lb
	Sold to Pipeline	-	107	lb
	Steam (600 psig, 700°F)	83	83	lb
	Petroleum Coke	68	68	lb
	Sulfur	0.77	0.77	lb
	Waste Disposal [b]	5.42	5.42	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	18.65	25.14	kWh
	Fuel [c]			
	Purchased	2.18	2.17	MMBtu
	Total	3.06	3.05	MMBtu
	Makeup Water	0.53	0.54	bbl
	O_2	-	109	lb
	Refrigerant	13.58	13.58	MJ
	Steam			
	50 psig	232	232	lb
	450 psig	383	383	lb
	SAGD	1,569	1,569	lb

[a] Same as Table 1, footnote "a."
[b] Mass of solids in brine from one of process units.
[c] Same as Table 1, footnote "b."

The total capital investment for the complete SAGD facility and an air-fired upgrading plant is $1.300 billion; with an oxy-fired upgrading plant, the cost rises to $1.328 billion. The largest capital cost for the air-fired heating system is for SAGD (25% of the total). A breakdown of all capital costs is available in the report.

The base case supply prices for this scenario (air-fired) as a function of hurdle rate are given in Table 9. Taxing CO_2 at the rate of $25 per ton increases the base case supply price by $4.68 to $88.62/bbl at a 0% hurdle rate.

Table 9. Supply price for air-fired in situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Drilling	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29
SAGD	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83
Upgrading [a]	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31
Taxes	$ 11.10	$ 13.77	$ 17.10	$ 20.90	$ 25.19	$ 30.38	$ 36.31
Oil Royalties	$ 8.92	$ 9.83	$ 10.92	$ 12.16	$ 13.57	$ 15.20	$ 17.05
Net Earnings	$ -	$ 4.94	$ 10.70	$ 17.29	$ 24.72	$ 33.19	$ 42.71
Maintenance	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87
Other [b]	$ 18.27	$ 18.33	$ 18.40	$ 18.48	$ 18.57	$ 18.68	$ 18.79
Supply Cost	**$ 85.59**	**$ 94.18**	**$ 104.41**	**$ 116.13**	**$ 129.35**	**$ 144.75**	**$ 162.17**
Other Revenue	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
Oil Supply Price	**$ 83.93**	**$ 92.52**	**$ 102.76**	**$ 114.47**	**$ 127.70**	**$ 143.10**	**$ 160.52**

[a] *Same as Table 7, footnote "b."*
[b] *Same as Table 2, footnote "c."*

Detailed supply price breakdowns and an analysis of the sensitivity of the supply price to a range of parameters are available in the report.

Economic Impact Analysis

An input-output analysis evaluates potential economic impacts arising from a 50,000 BPD ex situ oil shale project and a 10,000 BPD ex situ oil sands project from the point of view of two regions: the State of Utah as a whole and the Uinta Basin. The impacts associated with the projects' four-year construction phase are estimated separately from those of the 20-year operations phase. Because the reported estimates are for a successful industry, impact estimates for projects unlikely to realize commercial success are as speculative as the project itself.

Table 10 reports the economic impacts by region associated with the operations phase. In this analysis, one-third of total expenditures are expected to be spent in the Uinta Basin, while one-half are expected to be spent in the State of Utah. As there is no historical data on purchases, these fractions are simply assumed. If the actual amount is higher or lower by some factor, the estimated impacts are increased or reduced by the same factor because of the linearity of the input-output model.

Table 10. Economic impacts attributed to the operations phase of the ex situ development scenarios during the 20 years of production. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	Value-Added
Tosco II oil shale—State of Utah	6,274.6	10,996.2	2,495.6	58,954	6,203.9
Tosco II oil shale—Uinta Basin	4,141.3	5,220.5	1,250.7	26,304	—
Paraho Direct oil shale—State of Utah	5,871.6	10,353.6	2,245.6	50,468	5,853.7
Paraho Direct oil shale—Uinta Basin	3,875.2	5,047.8	1,130.1	21,879	—
Ex situ oil sands—State of Utah	1,525.5	2,746.1	622.2	15,013	1,493.7
Ex situ oil sands—Uinta Basin	1,006.8	1,320.3	344.8	7,388	—

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1 Introduction

1 Introduction

In 2001, an independent, non-partisan task force examining 21st century domestic energy challenges likened the U.S. energy posture to "traveling in a car with broken shock absorbers at very high speeds such as ninety miles an hour. As long as the paving on the highway is perfectly smooth, no injury to the driver will result from the poor decision of not spending the money to fix the car. But if the car confronts a large bump or pothole, the injury to the driver could be quite severe regardless of whether he or she was wearing a seatbelt" [1].

Numerous events since 2001 have intensified and complicated the nature and depth of today's domestic energy challenges. Some of the more salient of these events have been: the energy security implications of U.S. dependence on foreign oil in the wake of the September 11th attacks and subsequent military engagements; the 2007 financial crisis, ensuing recession and related instabilities in energy pricing; the 2010 British Petroleum/Deepwater Horizon oil spill off the Gulf Coast and the subsequent focus on environmental risks associated with pursuing increasingly less accessible oil; the recent boom in domestic oil and gas production from hydraulic fracturing; the waxing and waning attention to climate change; and the extreme levels of factionalism within American politics and society. Analytic consensus across the political spectrum that the United States faces numerous impending energy challenges —ranging from peak oil to military vulnerabilities due to reliance on fossil fuels to irretrievable tipping points in global temperatures—is ubiquitous. Lacking from these several analyses, however, is consensus on how to manage and meet the energy challenges of the 21st century.

This lack of agreement on energy policy direction and priorities is complicated by projected increases in domestic energy consumption. U.S. Energy Information Administration (EIA) projections show primary energy use in the U.S. increasing from approximately 95 quadrillion British Thermal Units (Btu) in 2010 to approximately 115 quadrillion Btu in 2035, as shown in Figure 1.1. Energy demand for the transportation sector is also projected to increase through 2035, with future domestic liquid transportation fuels supplied from increasingly difficult-to-produce oil reserves and biofuels (see Figure 1.2). EIA predictions contemplate that "[i]n the transportation sector ... petroleum's share of liquid fuel use declines as consumption of alternative fuels (biodiesel, E85, and ethanol for blending) increases ... [with] biofuels accounting for more than 80 percent of the growth in liquid fuel consumption" [2].

Unconventional fossil resources offer an alternative or supplementary domestic source of petroleum-based liquid transportation fuels. As conventional fossil fuel supplies become more challenging, carbon-intensive and expensive to produce, unconventional resources may compare more favorably. The emergent nature of the unconventional fuels industry creates an unprecedented opportunity to incorporate climate and environmental safeguards into technology and development requirements.

An unconventional fossil fuel is "not recoverable in its natural state through a well by ordinary production methods" [4]. The unconventional liquid fuel resources assessed in this report are oil shale and oil sands.

One argument against developing unconventional resources is that domestic energy policy should strive to replace conventional fossil energy sources with renewable, or at least greener, energy sources. While replacing fossil fuels with greener fuels is not going to change consumptive behavior, proponents of this argument assert that it does more to address looming challenges than

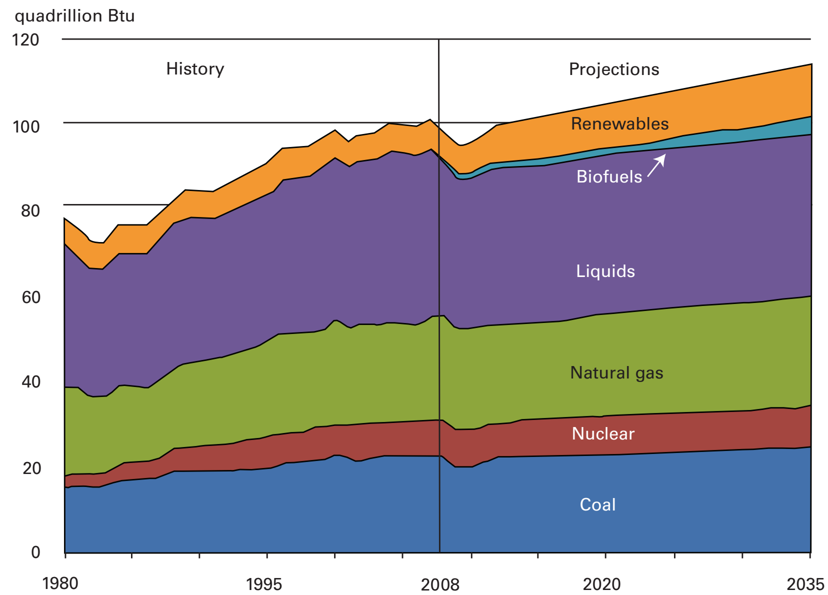

Figure 1.1: Primary energy use by fuel, 1980–2035; from [2].

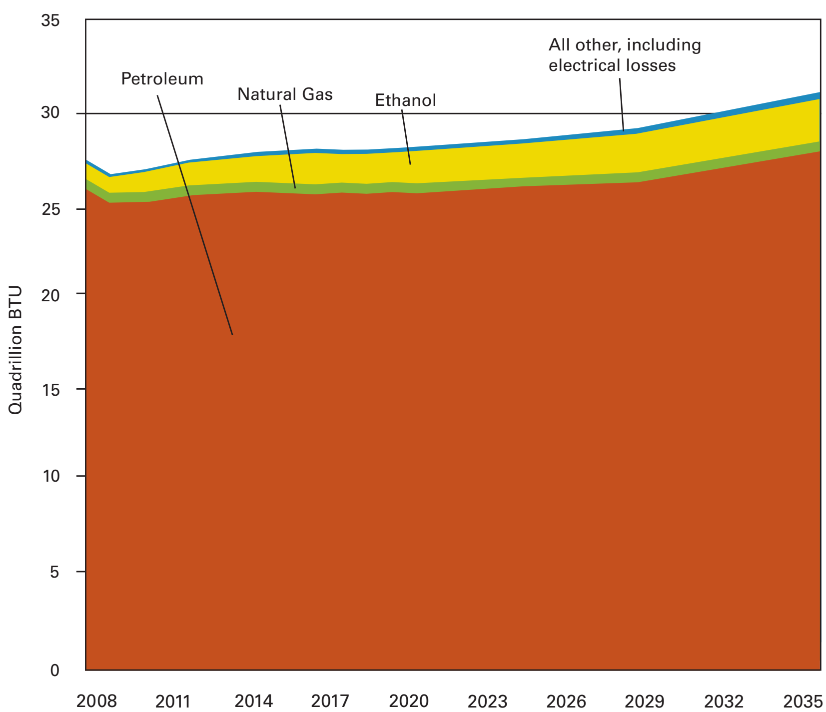

Figure 1.2: U.S. transportation energy, 2008–2035; from [3].

replacing conventional fossil resources with unconventional ones. Another argument is that development of unconventional resources will divert national attention and support from longer-term energy supply solutions by prolonging contemporary lifestyle and consumption patterns despite looming energy and climate realities and challenges.

The most common argument in support of developing unconventional fuel resources is that this development would mitigate the risk of any prolonged interruption of our fossil-based liquid transportation fuel supplies will destabilize our economic and national security. According to proponents of this argument, such an interruption is less likely to occur to the extent that the U.S. reduces its significant economic dependence on foreign supplies by developing domestic liquid transportation fuels from unconventional sources. Another argument draws on national security interests, positing that the domestic funds expended on OPEC fossil fuel supplies directly benefit many countries that are politically antagonistic to U.S. policies and interests and that domestic unconventional resources represent a meaningful alternative to these more diplomatically fraught fossil fuel supplies. Yet another argument in support of development is similar to arguments made on behalf of "clean coal"; namely that the U.S. is quite far from transitioning away from fossil fuels as the primary basis of its energy economy and that developing unconventional liquid fuel resources is essential in light of dwindling conventional petroleum supplies. Development supporters assert that unconventional fossil resources could serve as a secure, domestic bridge fuel between our current political, economic and lifestyle model and the largely indeterminate, greener model of the future.

This report seeks to assess significant impediments to development of U.S. unconventional fuel resources—specifically oil shale and oil sands—in today's economic and political world. In large part this assessment addresses the conjoined hurdles of relevant costs, production levels and infrastructure that are essential to developing successful industries around unconventional resources. However, these logistical and technical challenges are only part of the solution to developing these industries. Public opinion, political support, and effective management of the public costs associated with commercializing unconventional resources are all essential elements of successful and long-term resource development.

1.1 Absence of a Federal Unconventional Fuels Policy

Arguably the most significant impediment to unconventional fuel development is the absence of comprehensive and long-term federal energy policies that articulate an appropriate future role for these fuels in the domestic energy portfolio. The Obama Administration, including the Department of Energy (DOE) under Secretary Chu and the Department of Interior (DOI) under Secretary Salazar, has taken the position that all energy sources need to be considered as part of the domestic energy portfolio [5]. However, specific encouragement of unconventional fuel development has not been widely evident. With regard to oil shale, in 2009 the DOI issued a call for another round of oil shale Research, Development and Demonstration (RD&D) leases, but final, approved lease proposals have yet to emerge from the agency's internal review process [6]. With regard to oil sands, both the Administration and allied Congressional leaders have taken a largely passive policy approach to U.S. dependence on Canada's oil sands. They have affirmed the importance of the U.S. – Canada relationship and their shared commitment to addressing climate change and energy security while declining to call for any deviation from current levels of U.S. imports of Canadian oil sands-based synthetic crude oil (SCO) [6]. Denying approval for the expansion of the Keystone XL Pipeline presents the only notable policy challenge to the U.S. support of Canadian oil sands [7].

The purpose of the RD&D leases, issued by the Bureau of Land Management (BLM) on small test sites on the public lands, is to test and refine oil shale technologies.

The Keystone XL Pipeline is a proposed pipeline expansion (nominal capacity of 900,00 barrels per day or BPD) to transport SCO from Alberta to Texas). The Keystone XL project has met with myriad objections from oil refineries, environmental groups and some U.S. politicians. President Obama issued a decision in January 2012 to reject the Keystone XL application. TransCanada, the company proposing the Keystone XL Pipeline Project, is expected to reapply.

While the Obama Administration may not be implementing policies that directly seek to promote or deter development of domestic unconventional fuels, certain measures advanced by the Administration have significant, indirect implications. One such measure was announced on October 1, 2010, when the Environmental Protection Agency (EPA) and Department of Transportation (DOT) jointly issued a Notice of Intent to develop stringent new greenhouse gas (GHG) emissions and fuel economy standards for future light-duty vehicles (model year 2017 and beyond) [9,10]. These standards were developed in collaboration with California's Air Resources Board (CARB), culminating in a final rulemaking in October 2011 [11]. An additional proposed rulemaking is expected for heavy-duty vehicles (beginning in model year 2014), which will target GHG emission reduction from diesel fuel vehicles. The standards these regulations enact certainly bear on the future financial and market viability of liquid transportation fuels derived from unconventional fuel resources.

CARB formulated California's 2007 low-carbon fuel standards, which were criticized by both biofuels and Canadian oil sands producers as discriminating against their fuels [12,13].

1.2 Divergent Federal and State Paths for Unconventional Fuel Development

The absence of a comprehensive federal energy policy will likely increase the divide between federal and state unconventional fuel development policies. Oil shale is perhaps the clearest example of the potential consequences of these separate development trajectories.

The majority of domestic oil shale resources are on federal land. DOI promulgated oil shale leasing regulations [14] and opened lands within Colorado, Utah, and Wyoming to application for commercial oil shale leasing [15]. Nevertheless, no leasing activities ensued due in part to judicial challenges to both the leasing program and the 2008 Oil Shale and Tar Sands Programmatic Environmental Impact Statement (PEIS). Pursuant to a settlement of those lawsuits [16,17], BLM completed a revised Oil Shale and Oil Sands PEIS in 2012 [18]. As a practical matter, commercial leasing of federal land will not proceed until the regulatory landscape comes into clearer focus. Even if commercial leasing were to begin, the environmental analysis required to proceed with development would take years to complete.

The 2008 PEIS designated which federal lands would be open for leasing.

In contrast to federal lands, Utah in general, and Utah's School and Institutional Trust Lands Administration (SITLA) in particular, are "open for business as it relates to oil shale" [19]. In a 2008 analysis by Keiter et al. [20], SITLA had 99 active leases covering almost 100,000 acres (40,500 hectares). SITLA oil shale leases are not subject to federal multiple-use, sustained yield mandates, nor to the environmental impact statement requirements applicable to federal lands [21,22]. Moreover, SITLA lands are managed to maximize income and can be developed more rapidly than comparable federal lands [23]. For SITLA lands and leases, the economic return for SITLA beneficiaries "is paramount and must always prevail over any conflicting public use or purpose" [24,25]. While SITLA is a minor player in comparison to the federal government, SITLA controls a 25 gallon per ton (GPT) oil shale resource equivalent to 12.8 billion barrels of oil—almost as much as the entire Prudhoe Bay Oil Field [26,27]. Even as a minor player, SITLA has the potential to support a sizeable commercial oil shale industry, and its resources are readily developable.

Potential oil shale development on non-federal lands has several important implications. First, Utah's oil shale resources are scattered across the Uinta Basin; development of this resource will require road, pipeline, and electrical transmission access across federal lands. Failure to coordinate between the federal and state governments could delay development or result in redundant or inefficient infrastructure construction with increased environmental impacts. Second, the largest consolidated blocks of SITLA and private lands are located along the Mahogany Outcrop in areas where oil shale resources are potentially recoverable through surface mining. Consequently, the availability of SITLA lands may drive surface mining technology development rather than in situ methods.

WIth in situ methods, oil is produced "in-place"; that is, the resource is left in the ground.

Control of oil sands resources within Utah is also fragmented. BLM controls approximately 57 percent (%) of the lands overlying oil sands within the eleven congressionally designated Special Tar Sands Areas (STSAs) [28,29]. Other major overlying landowners include SITLA (14%), private landowners (10%) and tribal government (8%) [20]; each one of these entities is a majority landowner within one STSA. These non-federal landowners also control access to unquantified oil sands resources outside of the designated STSAs. Therefore, as with oil shale, federal inaction does not preclude oil sands development even though development of scattered non-federal parcels could decrease economic efficiencies and increase the scope of environmental impacts.

Utah illustrates the implications of the absence of a comprehensive federal policy on unconventional fuel development. If unconventional resources on state lands are developed first or without coordination, the federal government will have less opportunity to shape any nascent oil shale and oil sands industries consistent with national energy and environmental policy priorities and objectives.

1.3 Anthropogenic Climate Change

One of the primary drivers of the domestic energy policy vacuum is the continuing international and domestic inability to reach agreement on effective and fair strategies for addressing releases of potentially climate-changing emissions. The Kyoto Protocol, representing the most comprehensive international treaty on climate stabilization targets and GHG emissions reductions, expired at the end of 2012 [30]. The 2009 United Nations summit in Copenhagen failed to yield a binding international climate agreement, although it did result in several individual countries pledging voluntary initiatives on reducing GHG emissions [31]. Whether these initiatives will coalesce into meaningful, comprehensive international action remains unclear, leaving the status of such future international climate efforts in limbo [32]. In the absence of international consensus, cap-and-trade and other GHG emissions reduction programs are being pursued by the European Union, the United Kingdom and Australia, and such programs are influencing the decisions of companies like Total and Shell, both of which are pursuing oil shale development [33-35].

1.3.1 Domestic Climate Legislation

At present, the U.S. has no federal legislative regime addressing anthropogenic climate change. While various congressional efforts directed toward climate change legislation have not proceeded to enactment, the Obama Administration has pledged to continue working towards mandated GHG emissions reductions. However, present economic conditions and the changing face of Congress are likely to hamper efforts to reach legislative consensus on climate-related strategies. Absent Congressional action, EPA is poised to regulate carbon as a "pollutant" under the Clean Air Act (CAA) [36]. EPA's 2011 to 2015 strategic plan lists "[t]aking action on climate change and improving air quality" as the first of its five strategic goals [37]. EPA has recently taken steps with DOT to set GHG emissions standards for light duty vehicles [38], as well as creating reporting requirements for GHG inventorying purposes [39].

Several state and regional efforts to control GHG emissions have been attempted, such as the Western Climate Initiative and the Regional Greenhouse Gas Initiative. However, these multi-state efforts have been beleaguered by multiple states opting to change course and withdraw from these carbon management initiatives [40,41].

The exception to the prevailing legislative inertia is California, which enacted an ambitious state plan to combat climate change, the Global Warming Solutions Act of 2006 (GWSA) [42]. A 2010 referendum proposing to suspend implementation of GWSA until California's unemployment rates stabilized was defeated by voters by a margin of 61% to 39% [43]. Also calling for concerted action are many energy investors, insurers and developers, including oil companies, who have become increasingly vocal on the need for coherent regulation and pricing of carbon and other GHG emissions.

One element of California's GWSA, Renewable Portfolio Standards, succeeded in inducing regional neighbors, including Wyoming, to "green" their respective electricity exports to California [44-46].

1.3.2 Shifting Public Perceptions of Climate Issues

Global, national and state efforts to manage the effects of climate change have yielded few long-term results. Whether as a reaction to the absence of legislative progress, or in response to the weight of continuing economic stresses, or as a result of other factors entirely, the public perception of the urgency of climate-related issues has shifted measurably over the past four years.

In late 2008, The Six Americas Study, undertaken by the Yale Project on Climate Change and the George Mason University Center for Climate Change Communication, completed an "audience segmentation analysis" of the American public in order to analyze how different groups within the population were responding to the issue of climate change [47]. The study identified six such audiences, which the study characterized and quantified as:

> "The Alarmed (18%) are fully convinced of the reality and seriousness of climate change and are already taking individual, consumer, and political action to address it. The Concerned (33%)—the largest of the six Americas—are also convinced that global warming is happening and a serious problem, but have not yet engaged the issue personally. Three other Americas—the Cautious (19%), the Disengaged (12%) and the Doubtful (11%)—represent different stages of understanding and acceptance of the problem, and none are actively involved. The final America—the Dismissive (7%)—are very sure it is not happening and are actively involved as opponents of a national effort to reduce GHG emissions."

Follow up research on the six audiences conducted in 2010 and 2011 found that views among and between them had shifted [48,49]. Detailed tracking of the growth and diminishment of each of the Six Americas audience segments at survey points between 2008 and 2011 is illustrated in Figure 1.3. In 2011, the status of the six audiences was: Alarmed (12%); Concerned (27%); Cautious (25%); Disengaged (10%); Doubtful (15%); and Dismissive (10%) [49].

Thus between 2008 and 2011, on the extreme edges of the survey's spectrum, the Alarmed segment shrunk by 33%, while the Dismissive segment grew by slightly less than 50%.

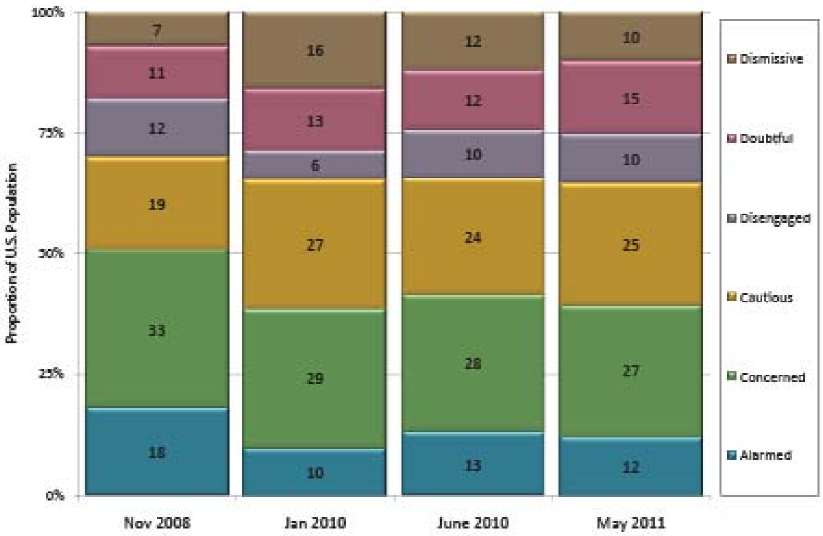

Figure 1.3: Changes in segment sizes in the Six Americas study, 2008 through 2011; from Leiserowitz et al. [49].

Although 67% of all respondents to the 2010 Six Americas survey held the view that "protecting the environment improves economic growth and provides new jobs" as compared to 33% who felt that protecting the environment reduced economic growth and came at the expense of jobs, only 5% identified the issue of global warming as "extremely important to me personally" and only 13% identified global warming as a "very high priority for the president and Congress" [48]. By contrast, in 2008, 11% of respondents identified the issue of global warming as extremely important to them personally and 21% believed global warming should be a very high priority for the next president and Congress [47].

When researchers revisited these issues in late 2012, they found that views appeared to have shifted yet again, with 77% of interviewees saying that global warming should be a "very high" priority for the president and Congress, 18% deeming it a "high" priority, 34% deeming it a "medium" priority, and 23% identifying it as a "low" priority [50]. A sizeable majority, 88%, expressed the view that the U.S. should make efforts to combat global warming even if those efforts had economic costs [50].

With respect to unconventional fuel development, this shifting public opinion landscape greatly complicates political efforts to effectively address climate issues and presents substantial challenges to developers and policymakers trying to secure investment and to chart a course for future development. In early 2011 and continuing through the 2012 election cycle, GOP lawmakers called for hearings on what they view as EPA's abuse of its authority in regulating GHG emissions under the CAA and "distortions of scientific evidence regarding climate change" [51]. Perpetuation of this political debate over the validity of global warming will almost assuredly diminish public consensus on when and how to address climate stabilization and will further delay policymakers in bringing regulatory and pricing certainty to the GHG externalities.

1.4 Past Evaluations of Commercial Unconventional Fuels Development

Over the past several decades, numerous attempts have been made to quantify the supply costs and economic impact of unconventional fuels development. In 1979, STRAAM Engineers published the Capital and Operating Cost Estimating System Handbook for the mining, retorting, and upgrading of oil shale in Colorado, Utah, and Wyoming [52]. This handbook provides an estimating method through the "use of equations, factors and curves for preparation of feasibility/conceptual type estimates for capital and operating costs of oil shale projects" utilizing the oil shales of Colorado, Utah, and Wyoming. Included in the handbook are costs for both mining/surface retorting and in situ retorting methods, upgrading, and transportation for production rates ranging from 9,400–151,000 BPD of SCO. The handbook was prepared for BLM to assist them "in the valuation of oil shale deposits which may be considered for leasing, exchange or patent" [52].

"Supply cost" refers to capital and operating costs put in terms of cost-per-barrel.

SCO is raw shale oil (from oil shale) or bitumen (from oil sands) that has undergone "upgrading"—processing that renders a product physically similar to conventional refinery feedstock.

The problem that existed when this handbook was published persists today, namely that U.S. oil production costs from unconventional fuels such as oil shale and oil sands have not been established. The STRAAM handbook notes that, "Many studies have been made, pilot and semi-works plants have been operated, calculations and prognostications abound in the literature; but a functioning oil shale mine with processing plant and a marketable product has not been achieved. It is necessary to simulate the capital and cost based on the oil shale literature, gross estimates provided by entities active in oil shale development, experience in similar industries and engineering judgement" [52].

In 2005, the RAND corporation published "Oil Shale Development in the United States - Prospects and Policy Issues" [53]. The authors scaled cost information available from the Colony and Union oil shale projects and from design studies performed in the 1980s to get "a very rough estimate of the anticipated capital costs for mining and surface retorting plants." They estimated that a first-of-a-kind 50,000 BPD mining/surface retorting operation would incur capital expenditures in the \$5–\$7 billion range (2005 dollars) with operating costs in the \$17–\$23 per barrel range (2005 dollars). The authors projected that the price of a reference crude such as West Texas Intermediate (WTI) would need to be in the \$70–\$95 (2005 dollars) per barrel range for the oil shale operation to turn a profit given these capital and operating costs.

WTI is a crude stream produced in Texas and southern Oklahoma that serves as a reference for pricing other crude streams.

Also in the 2005 RAND report are preliminary cost estimates for Shell's In-situ Conversion Process (ICP) [53], an in situ retorting technology. The authors, quoting a Shell source, estimate costs between \$150–\$200 million for a pre-commercial demonstration operation producing 1,000 BPD in Colorado's Piceance Basin. The breakdown between capital and operating costs is not reported nor is the time period over which production would occur.

A study published by DOE's National Energy Technology Laboratory in 2006 considered four options that could be implemented in the U.S. to reduce dependence on foreign oil [54]. One of those options is the development of 4,000,000 BPD of shale oil production capacity over 20 years. The report lists some of the assumptions employed in the cost analysis: the technology employed is Shell's ICP; the first three facilities begin producing in year eight with three additional facilities coming on-line each year thereafter; the product stream is two-thirds liquid and one-third gas; each 100,000 BPD plant requires one gigawatt (GW) of electrical power provided by a coal-fired power plant; construction costs for each facility are $8 billion (2004 dollars); and operating costs are $500 million per year (2004 dollars). Costs for product transportation, refining, and other infrastructure are not included. The report does not state whether the liquid product requires further upgrading prior to refining, and costs of upgrading are not included in the analysis. Additionally, there are no publicly available references for the assumptions made as to capital and operating costs.

Results from the analysis [54] include direct costs for plant construction and operation over a 20-year period, impact on sales and jobs, industry profit, and government tax revenues. For example, capital costs for construction are estimated to exceed $100 billion before production of liquid fuels begins in year eight. However, the authors note that the cost estimates are subject to a high degree of uncertainty [54].

More recently, several oil shale companies have publicly reported cost estimates. In 2009, Oil Shale Exploration Company (OSEC) completed a commercial feasibility study for a mining/surface retort plant producing 50,000 BPD of upgraded shale oil on the White River RD&D lease and/or private lands owned by OSEC [55]. The mining plan called for oil shale production of 30 million tons per year with a surface retorting operation that included 12 Petrosix retorts (retort technology developed by Petrobras [56]) and a fines retort for the 10% of the mined rock that was crushed to a size too small to process with the Petrosix technology. The reported "all-in" production costs per barrel were estimated at $39–$45 for a product with an American Petroleum Institute (API) gravity of 35º, low sulfur content, and a cetane number of 57 [55]. As with the Shell estimate, it is difficult to determine what exactly was included in the production cost and on what the reported numbers are based.

Enefit, an Estonian shale oil producer and technology developer, acquired 100% of OSEC shares in early 2011. With this purchase, Enefit became the owner of large tracts of privately owned oil shale properties in the Uinta Basin. Enefit is planning to construct an oil shale production plant with a 50,000 BPD capacity [57].

API gravity is a relative specific gravity scale; water has an API gravity of 10º. Heavy crude oils have low API gravity while lighter crude oils have high API gravity. Cetane number (CN) is a measure of a fuel's ignition delay during compression ignition. The minimum CN is generally set at 40 with premium diesels having higher CN [58].

At the 30th Oil Shale Symposium in 2010, Red Leaf Resources reported costs for a proposed 9,500 BPD modified in situ operation employing the Ecoshale technology [59]. The proposed operation is located on Red Leaf's SITLA oil shale leases in Utah's Uinta Basin. For the analysis, Red Leaf assumed that four EcoShale™ capsules would be brought on line each year for a total of 116 capsules, that two capsules would be in production simultaneously, that the production per capsule was 866,000 barrels of oil, and that the capital expenditure (capex) and operating expenditure (opex) contingency fees were 20% and 15% respectively (although percentages of what is unclear). Other stated assumptions include a corporate tax rate of 38%, a property tax rate of 1.2%, and a royalty rate that starts at 5% and, after five years of production, increases 1% annually to 12.5%. The inflation rate was assumed to be 2% and WTI was assumed to sell for $80 per barrel (2010 dollars) with adjustments for inflation. The total capital costs for this operation were reported to be $266 million or $2.66 per barrel of oil produced.

Capex refers to assets that are bought to produce the oil and which depreciate over time. Opex refers to ongoing costs incurred in producing the oil such as utilities, labor, maintenance, and taxes.

According to the Red Leaf netback analysis, the netback in 2015 is $25.35 assuming a 2010 WTI price of $60 per barrel; for a WTI price of $80 per barrel, it is $38.90 [59]. The netback in 2030 is $31.58 for a 2010 WTI price of $60 per barrel and $49.71 for a WTI price of $80 per barrel. The per barrel costs included in the netback analysis are opex, transportation, royalties, and taxes; capex is not listed as a contributor to per barrel costs. In 2015, this per barrel cost is $41.70 for $60 per barrel WTI pricing and $50.50 for $80 per

The netback is the revenue from one unit of oil minus the sum of all costs associated with bringing that unit of oil to market (e.g. production, upgrading, transportation, royalties, etc.) [61].

barrel WTI pricing. A sensitivity analysis conducted by Red Leaf shows that the investor rate of return (IRR) is extremely sensitive to the price of WTI and somewhat sensitive to the capital cost. Red Leaf states on their website that "Recent independent analysis estimates the EcoShale™ In-Capsule Technology process production costs to be approximately $25/bbl (including capex). These estimates are dependent on the project scale implemented on Utah leases and based on specific resource geology and field test results" [60].

The economics of the Canadian oil sands industry are well-established for both mining and in situ operations. A 2008 report by the Canadian Energy Research Institute (CERI) estimates the per barrel cost of SCO from both mining and in situ operations [62]. For the set of assumptions used by CERI that incorporated feedback from industry, the per barrel cost in 2007 Canadian dollars (C$) of producing SCO at a scale of 100,000 BPD is estimated to be C$71.84–C$73.55. However, the situation is much different for U.S. oil sands development. In early 2008, the Congressional Research Service published a report on North American oil sands that made the following statement, "The U.S. government collaborated with several major oil companies as early as the 1930s to demonstrate mining of and in-situ production from U.S. oil sand deposits. However, a number of obstacles, including the remote and difficult topography, scattered deposits, and lack of water, have resulted in an uneconomic oil resource base....U.S. oil sands would likely require significant R&D and capital investment over many years to be commercially viable" [63]. The report details capital and operating costs for Canadian oil sands production over time, but there are no estimates of costs for U.S. production.

The National Strategic Unconventional Resource Model (NSURM) was developed by the Office of Naval Petroleum and Oil Shale Reserves in the winter of 2005–2006 to support the Unconventional Fuels Task Force mandated by Congress in section 369 of the Energy Policy Act of 2005 [64]. Its purpose is to evaluate the potential for domestic unconventional liquid production from oil shale, tar (oil) sands, and other sources. The NSURM report notes that the model was developed "from existing, vetted models wherever possible. The oil shale component has been thoroughly reviewed by experts in the oil shale industry, policy and program analysts from DOE, as well as consultants specialized in resource evaluation, technology characterization, project economics, and resource modeling" [64].

An second revision of the NSURM was published in 2012 [65]. This revision "...adds the capability of determining water requirements, CO_2 production, and energy efficiency..." for the various technologies that are included in the model.

The NSURM uses a database of 25 federal oil shale tracts and 28 oil sand leases to compute technical recovery based on the technology employed (ex situ versus in situ) and characteristics of the tract (petrophysical and geological); the model assumes that all tracts/deposits are available for development. The site-dependent maximum capacity is determined by the model. For oil shale mining projects, the maximum capacity is 100,000 BPD and for oil sands mining projects it is 90,000 BPD. Capital costs for ex situ oil shale production were obtained from a variety of sources, including the Prototype Leasing Program in the early 1980's, and from vendor quotes. In situ capital costs were obtained from industry sources. Capital costs for all tar (oil) sand production processes were developed based on data from the Canadian oil sands industry. Operating costs for oil shale were calculated from data in the Prototype Leasing Program and from other unidentified sources while those for tar (oil) sands primarily used studies and annual reports from the Canadian oil sands industry. Cost categories for both capital and operating costs can be found in the NSURM [64].

The NSURM determines economic viability through net present value (NPV), which is the same methodology employed in this report (see Section 5). The report states that, "the net present value is the cumulative after tax cash flow discounted using a specific rate of return. If the net present value is positive, the project is profitable and considered economic" [64]. The only project analyzed in the report is a generic oil shale project and the conclusion is that "the project is best characterized as "capital intensive" with a relatively long payout period." Because the NSURM was unavailable to the authors of the present report, it is unclear how the cost analyses resulting from its application to the scenarios in this report would compare to the results published herein.

There are numerous assumptions underlying the various cost projections reported above as well as multiple ways to determine economic viability (netback analysis, NPV, etc.). Reports such as the 2005 RAND report [53] have a detailed summary of the assumptions employed in the analysis while other sources are more vague. One must also consider the final product being sold from the process. Is it a refinery-ready stream or does it require further upgrading? Cost analyses that include upgrading to a WTI standard will be much different than those selling bitumen at a discounted rate.

1.5 Scope of this Report

Although U.S. production of unconventional fuel from oil sands and oil shale has been shown to be technically feasible [66, 67], there is currently no commercial scale production of either resource. Without established costs, this report necessarily relies on various cost estimating methodologies to reach an educated best-guess of what the economic viability of any project might be. In addition, the analyses presented in this report exceed those of other reports by: estimating all-inclusive costs for extraction, upgrading, and transport to market; applying the same methodology for determining costs to all of the scenarios analyzed; itemizing all of the costs for each process to allow for easy comparison to other studies; and investigating the uncertainty associated with inputs and assumptions for each scenario and reporting the impact they have on economic viability.

This report offers detailed analyses of four unconventional fuel development scenarios in Utah's Uinta Basin. These scenarios are:

- Ex situ extraction (underground mining, surface retorting) of oil shale
- In situ extraction (underground heating) of oil shale
- Ex situ extraction (surface mining, surface processing) of oil sands
- In situ extraction (Steam-Assisted Gravity Drainage or SAGD) of oil sands.

The locations of the scenarios, shown in Figure 1.4, were identified at a coarse geographic scale for the economic modeling purposes of this report. Requirements contained in forthcoming amendments to the federal oil shale leasing rule, pending revisions to federal land use plan amendments determining which lands will be available for leasing, sage grouse habitat that renders an area ineligible for leasing, and other land use considerations may impact actual site selection and necessitate further consideration for actual development. However, for analytical purposes, this report assumes that comparable sites are available.

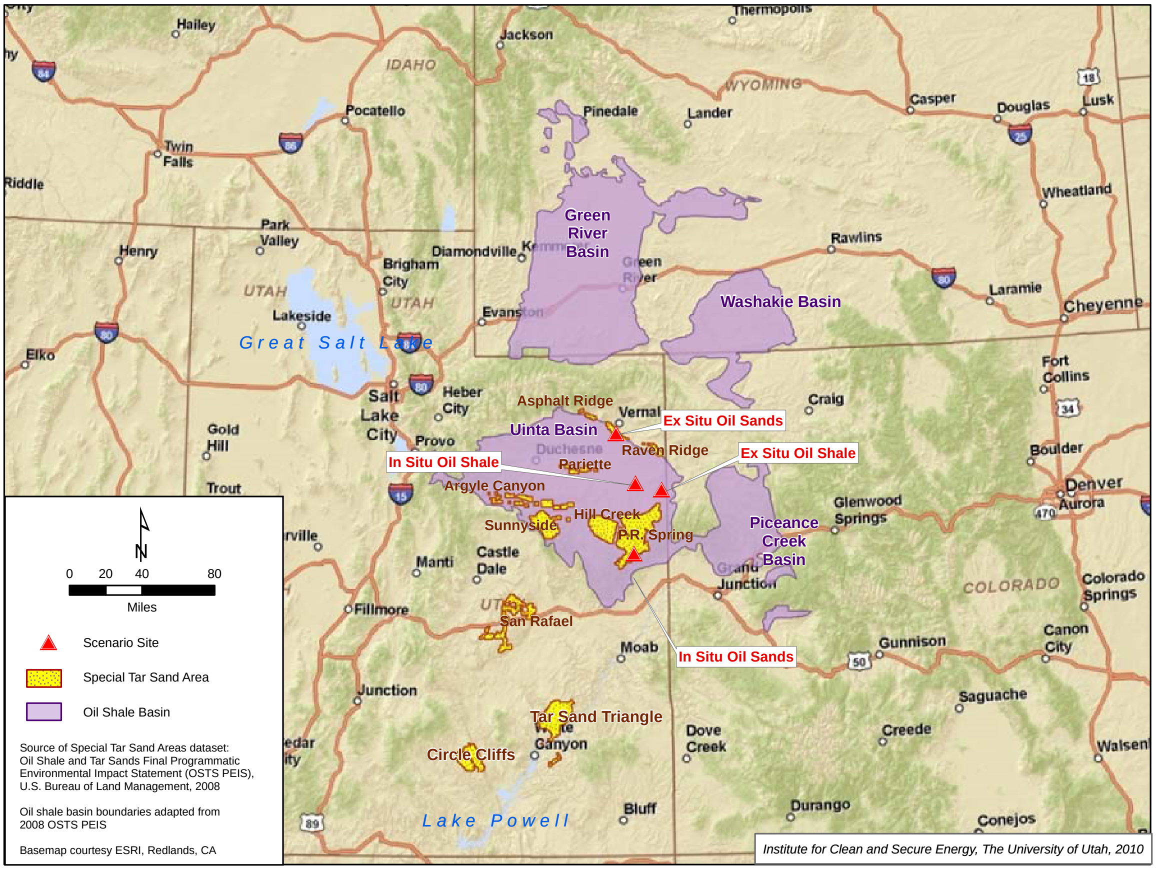

Figure 1.4: Map of location of oil shale and oil sands scenarios in Utah's Uinta Basin.

The Uinta Basin location was chosen for several reasons. First, the Uinta Basin is the only location in the U.S. with significant deposits of both resources, facilitating a more direct comparison of resource economics. Second, Utah Governor Gary Herbert has publicly supported unconventional fuels development. When welcoming the Estonian oil shale company Enefit to Utah, Governor Herbert stated that "Oil shale has the potential to be one of our nation's greatest untapped natural resources, and the Uinta Basin here in Utah has potentially millions of barrels of recoverable oil" [68]. Third, while Colorado's Piceance Basin has larger oil shale resources than the Uinta Basin, there are groundwater issues to consider. One of the richest oil shale zones, the Mahogany zone [69], separates the most important bedrock aquifers, the upper and lower Piceance Basin aquifer systems. Groundwater travels down from the upper aquifer system, through the Mahogany zone, and into the lower aquifer system [70], creating technical and economic difficulties for in situ extraction methods. Shell developed a freeze wall method to address these challenges, isolating a section of the Mahogany zone so that water could subsequently be removed and the deposit heated for in situ extraction [71]. To avoid groundwater problems on its RD&D oil shale lease, American Shale Oil (AMSO) is targeting the R-6 zone, a rich zone oil shale zone below the aquifer at a depth of just over 2,000 feet (610 meters), for in situ extraction [72]. In contrast, the Birds Nest aquifer in Utah's Uinta Basin is typically several hundred feet above the Mahogany zone. The main concern with groundwater relative to Uinta Basin oil shale development is that saline

The Piceance Basin is also known as the Piceance Creek Basin.

Shell's target depth was 1,000–2,000 feet (305–610 meters).

water disposal into the Birds Nest aquifer by conventional gas producers may create unforeseen economic and technical hurdles [73].

The two oil shale scenarios contemplate a production capacity of 50,000 BPD while the production capacity of the two oil sands scenarios is 10,000 BPD. The scenarios encompass extraction with the subsequent upgrading of the extracted product (raw shale oil and bitumen) to make a light, low-sulfur SCO that is pipelined from the point of upgrading to a refinery capable of refining it. The scale of these operations is not large compared to daily U.S. oil consumption, which averaged 18.8 million BPD in 2011 [74], but it is sufficiently large to make these types of synthetic crudes an important regional refinery feedstock and to warrant a dedicated pipeline to provide a reliable supply to the refiner, a critical factor in generating refinery sales.

By way of comparison, 2010 average daily production of conventional crude oil in the two counties comprising the Uinta Basin, Uintah and Duschene, was 48,000 BPD [75].

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2 U.S. Unconventional Liquid Fuel Resources

2 U.S. Unconventional Liquid Fuel Resources

Geologically speaking, oil shale is a petroleum source rock that was never buried deeply enough for the its bound organic material, kerogen, to undergo catagenesis to form oil and gas [1]. Oil sands are a consolidated or unconsolidated reservoir rock containing an extremely viscous (greater than 10,000 centipoise or cP at reservoir conditions) organic material known as bitumen [2]. They are remnants of former crude oil reservoirs where the oil has been degraded to bitumen by biological, chemical, and physical processes [3,4].

***Source rock** is a fine-grained, sedimentary rock containing organic material that produces oil "given sufficient exposure to heat and pressure" [5]. The oil then migrates to **reservoir rock**, a permeable, porous subsurface rock (e.g. sandstone) in which oil is stored [6,7].*

This section provides a brief overview of the oil shale and oil sands resources in the Uinta Basin, including resource size, resource characteristics, and factors inhibiting development.

***Catagenesis** is the thermal degradation of organic matter by burial and heating in the range of 122°–302°F (50°–150°C) over millions of years [4].*

2.1 Oil Shale

The enormous magnitude of oil shale deposits in the United States, particularly the Green River Formation of Wyoming, Utah, and Colorado (see Figure 2.1), is well known. The United States Geological Survey (USGS) recently completed assessments of in-place oil shale resources in the Piceance Basin of Colorado and the Uinta Basin of Utah. The estimate of total in-place oil

A small portion of the Uinta Basin extends over the state line into Colorado as seen in Figure 2.1.

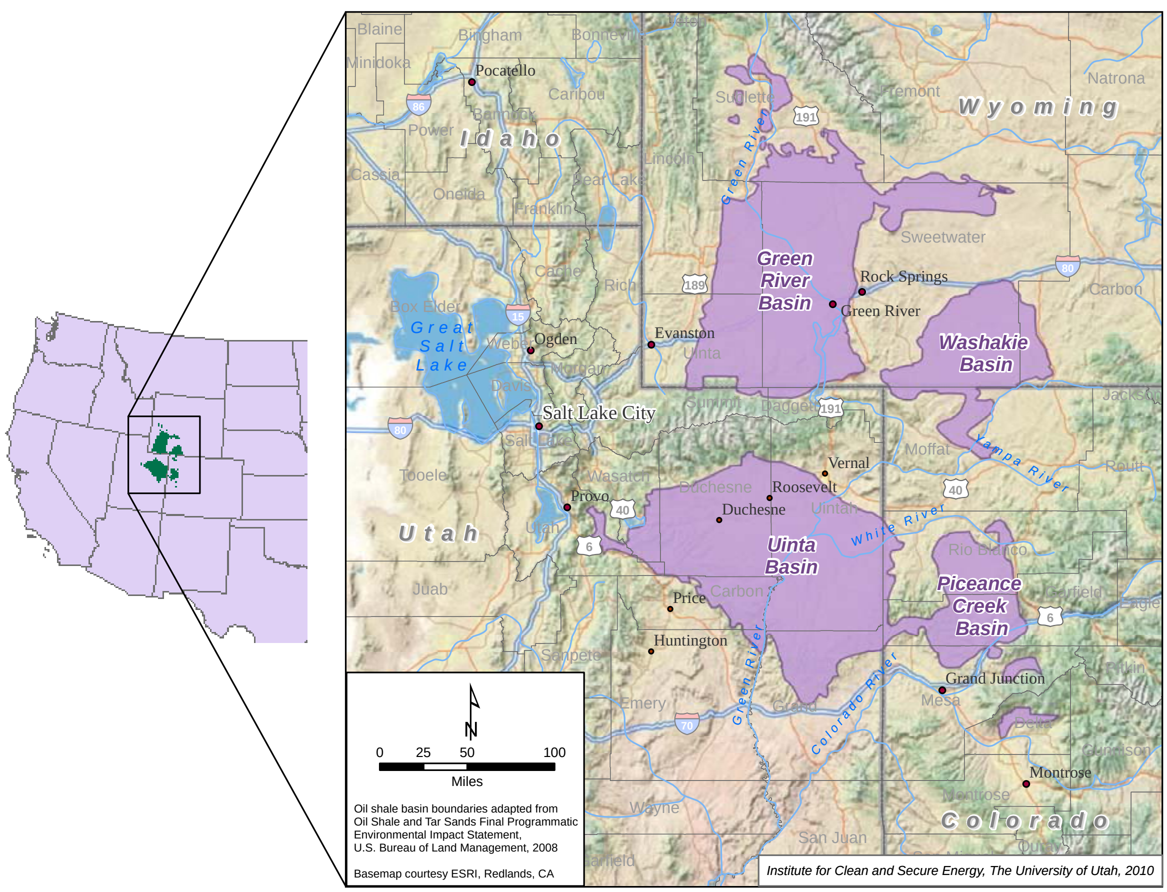

Figure 2.1: Location of Green River Formation showing main basins in purple.

for all oil shale zones (>0 GPT) in the Piceance Basin is 1.53 trillion barrels while that for the Uinta Basin is 1.32 trillion barrels [8,9]. A 2008 study by the Utah Geological Survey (UGS) estimates the total resource size for Uinta Basin deposits containing at least 15 GPT oil shale to be 292 billion barrels [10].

The richness of an oil shale deposit is quantified by measuring the gallons of oil produced per ton of raw shale processed, or GPT.

A resource deposit is not a reserve until exploitation becomes technically and economically feasible. Shale oil was a commercial product in the U.S. between 1850 and 1860, but conventional oil production quickly surpassed and then eliminated shale oil production following the first successful oil well, which was drilled in 1859 [11]. Interest in oil shale has intensified several times over the past century, with the most recent oil shale boom in the Uinta and Piceance Basins linked to the energy crisis of the 1970s [12]. However, with the collapse of crude oil prices in the early 1980s, shale oil production collapsed as well. Exxon shuttered its large Colony Project in the Piceance Basin on May 2, 1982. On the day of the announcement, known locally as "Black Sunday," over 2000 people lost their jobs [13,14]. Union Oil continued to operate in Parachute, Colorado until 1991, the last active oil shale facility from this era [14].

Renewed commercial interest in oil shale development has been partially driven by higher crude oil prices and improved production technologies. Other contributing factors were BLM's initiation of its RD&D leasing program in November 2004 and the Congressional mandate for commercial oil shale leasing included in Section 369 of the Energy Policy Act of 2005 [15]. A second round of RD&D leasing was initiated by BLM in 2010, resulting in the issuance of two RD&D leases in Colorado [16].

2.1.1 Uinta Basin Oil Shale Resource Assessment

There have been several assessments of oil shale in the Utah portion of the Uinta Basin since the early 1960s. Historical assessments range from 165 billion barrels [17] to 321 billion barrels [18] with Trudell [19] in the middle at 214 billion barrels. All of these estimates are based on a minimum grade of 15 GPT, but since the studies look at different oil-shale horizons, they cannot be compared directly.

In 2008, Michael Vanden Berg at UGS published a new assessment of Uinta Basin oil shale resources. In this assessment, Vanden Berg notes that past assessments "concentrated on the Eocene Green River Formation's Mahogany zone in the southeastern part of the Uinta Basin, and were limited in the amount of drill hole data available at the time" [10]. Data for these assessments came from approximately 180 oil-shale-specific wells that were drilled between 1954 and 1983, mainly near the well-mapped outcrop of the richest oil-shale horizon, the Mahogany zone. The 2008 assessment investigated the entire Uinta Basin, utilizing data from the oil shale wells and from "hundreds of geophysical logs from oil and gas wells drilled over the last two decades" [10]. Vanden Berg created conversion equations for predicting oil yield from geophysical logs by correlating available Fischer assays with corresponding density and sonic measurements. He did not use Fischer assay data from oil and gas well rotary cuttings, considering the data unreliable due to possible contamination by uphole caving and to the mixing of cuttings over 10-foot intervals. The total in-place estimate of 292 billion barrels of at least 15 GPT oil shale was the result of this work. Vanden Berg computed the potential economically recoverable resource in the Uinta Basin at 77 billion barrels based on criteria that include a resource grade of at least 25 GPT, a deposit thickness of at least five feet with less than 3,000 feet of overburden, and a location on BLM, state, private, or tribal land that is not in conflict with current conventional oil and gas resources [10].

The most recent in-place oil assessment by Johnson et. al. [9] at USGS is a comprehensive, geology-based assessment of the Uinta Basin Eocene Green River Formation oil shales, regardless of richness. That is, no minimum GPT cutoff was used in the determination of the total in-place resource. Johnson et al. used cuttings data in their analysis due to the scarcity of core data in many parts of the Uinta Basin, but they acknowledge that it is "less precise than results from core because of the longer sample interval and ever-present possibility of contamination from uphole caving" [9]. They also note that results from a few rotary holes appear to give unreasonably high oil-yield values when compared with nearby holes and/or regional trends. The data from these types of holes were not included in their resource calculations. Their total in-place estimate of 1.32 trillion barrels was obtained by subdividing the oil shale interval into 18 "roughly time-stratigraphic intervals" and then assessing each interval for GPT, barrels per acre, and total barrels per 36-square mile township. The authors note that while the area underlain by oil shale in the Uinta Basin is more than double that in the Piceance Basin, 3,834 square miles (9,930 square kilometers) versus 1,335 square miles (3,460 square kilometers), the resource is of a lower grade and more disperse than the Piceance Basin resource [9]. However, as noted in Section 1, the rich oil shale zone known as the Mahogany zone is coincident with an aquifer system in the Piceance Basin while in the Uinta Basin, the major aquifer lies several hundred feet above the Mahogany zone.

2.1.2 Characteristics of Uinta Basin Oil Shale

Characteristics of oil shale from the Mahogany zone of the Uinta and Piceance Basins are given in Table 2-1. The numbers in the table represent an average of 10 samples from both Utah and Colorado; according to Baughman [20], the similarities in composition among all 10 samples are "striking." Of the organic portion of the sample, the carbon content is approximately 80% by weight and the carbon to hydrogen atomic ratio is 0.65. The mineral content is primarily carbonate minerals (dolomite and calcite). In the region of the Uinta Basin selected for the oil shale development scenarios in this report, the pay zone is predominantly 25 GPT oil shale, so an average Fischer assay of 25 GPT is used in oil shale cost calculations in subsequent sections.

The pay zone is defined as the oil shale interval where organic content equals or exceeds 25 GPT.

2.1.3 Oil Shale Challenges

The central economic challenge in recovering oil from oil shale is that present (international) commercial grades of oil shale are only about 13–23% by mass recoverable as energy. Green River oil shale in the Uinta Basin (see Figure 2.1) averages about 14% by mass recoverable as energy [21]. With ex situ production, the remaining mineral matter incurs a considerable expense for processing and environmentally acceptable disposal. By contrast, 70–100% by mass of conventional fuels, e.g. coal, oil and gas, consist of recoverable energy [21]. One technical approach to the lean-ore problem is in situ extraction, which leaves the rock in the ground and processes it there. Although technical feasibility has been demonstrated (e.g. Shell's ICP), thus far economic feasibility has not, and the future for in situ recovery is not clear. This assessment analyzes both in situ and ex situ extraction methods.

Mass percent usable energy by fuel: coal = 70 –90%, natural gas = 99+%, oil (excluding water) = 100%.

Table 2-1. Characteristics of Mahogany zone oil shale in Uinta Basin, Utah, and Piceance Basin, Colorado; from Baughman [20].

Numbers in this table represent an average of 10 samples.

wt% = weight percent

Mineral	Composition (wt%)
Dolomite	32
Calcite	16
Quartz	15
Illite	19
Albite	10
K feldspar	6
Pyrits	1
Analoime	1
Total Probable Composition of Organic Matter:	
Carbon	80.52
Hydrogen	10.30
Nitrogen	2.39
Sulfur	1.04
Oxygen	5.75
C/H atomic ratio	0.65
Moisture	0.38–2.93

A second key challenge in Utah's Uinta Basin involves the costs imposed by the location, a challenge shared by Colorado's Piceance Basin. The resource is generally remote and lacking nearby infrastructure. Water supplies within the basin are constrained, and their use for energy purposes has provoked serious social and institutional debate for over 30 years [22]. Given the sparse population in the area, the influx of workers needed for large-scale shale oil production would strain local infrastructure including housing, schools, and roads. A 2007 Institute for Clean and Secure Energy (ICSE) report estimates that a 100,000 BPD oil shale operation in the Uinta Basin would result in a population increase of 39–47% over 2005 levels [12].

A third challenge to oil shale development in the Uinta Basin is that the properties of shale oil produced may not be acceptable to a refinery, in which case post-production upgrading would be required. Upgrading increases the API gravity of the oil, lowers its pour point to acceptable limits, and reduces sulfur and nitrogen content [12]. It also removes heavy metals that can poison catalysts used in the refining process. However, upgrading greatly increases the cost of the refinery-ready product.

While lease availability is another significant challenge to potential developers, this report assumes that the requisite oil shale leases have been obtained such that development can proceed. A brief summary of leasing as it applies to both federal and state lands is found in Section 1.2.

The sites for the oil shale scenarios analyzed in this report were chosen specifically to minimize the first two challenges. In the area of the Uinta Basin where the scenarios are located, the 25 GPT interval is 100–130 feet thick (30.5–40 meters) [10]. The scenario sites are only a few miles from the town of Bonanza, thus reducing the cost of building utility lines and other infrastructure needed for development. To address the third challenge, this report assumes that any raw shale oil produced will require secondary upgrading (i.e. hydrotreating) to produce a refinery-ready product.

2.2 Oil Sands

The total U.S. oil sands resource is estimated at 76 billion barrels original oil in place (OOIP) with the largest deposits found in the state of Utah. The estimated resource size in Utah is 32 billion barrels OOIP [23]. Significant oil sands deposits are also found in California, Texas, Alabama and Kentucky, but data relating to these deposits is sparse and speculative. In the early 1980s, the USGS, under direction from Congress, designated seven STSAs in the Uinta Basin. These STSAs and several other oil sands deposits in the state are shown in Figure 2.2; the resource size for each of the Uinta Basin STSAs is listed in Table 2-2. The Uinta Basin oil sands are primarily in the P. R. Spring and Sunnyside deposits with a substantial additional resource in the Asphalt Ridge area. These deposits are geologically condensed, relatively shallow, thin layers of fluvial, oil-impregnated sandstone.

The term OOIP refers to the volume of oil present prior to any production.

Oil sands have been produced commercially in Canada since 1978 [26], with 2009 oil production of 1,281,000 BPD [27]. However, despite decades of research and pilot scale testing, commercial development of U.S. oil sands, specifically those in Utah, has been confined to the use of "native" asphalt as paving material in several western states, Ohio, and Japan [28].

Nearly all major oil companies performed core drilling, mapping, and exploratory activities on Uinta Basin oil sands deposits in the 1950s and 1960s. Processes used for commercial bitumen production in Canada (e.g. the Clark hot water process) and for commercial heavy oil production in California (e.g. steam floods) were tested at the pilot scale [28]. However, falling oil prices in the mid-1980s eliminated incentives to pursue oil sands development. An attempt to revive commercial development was made in 1997 when a pilot plant was jointly built by Crown Energy, Michigan Power, and Canadian Western Research Centre. The plant utilized a modified hot water extraction process and operated for 14 months beginning in 1999, but the venture was ultimately unsuccessful [28]. In September of 2007, Earth Energy Resources (now US Oil Sands, Inc.) submitted a permit application for a 213-acre (86-hectare) surface mine to the Utah Department of Natural Resources, Division of Oil, Gas, and Mining (DOGM). DOGM issued tentative approval for the mine in May of 2009, but that approval was put on hold pending multiple agency challenges brought by a consortium of environmental groups [29]. US Oil Sands received final agency approval in October of 2012. However, that agency approval is likely to be appealed in court [30]. US Oil Sands uses a citrus-based solvent to extract the bitumen from the sand, which is then impounded on site. The process purportedly requires low energy input, recycles 95% of the water used and uses best practice mining methods to rapidly reclaim mined areas [31].

US Oil Sands has more than 7,800 acres (3,200 hectares) of Utah state land under lease.

2.2.1 Uinta Basin Oil Sands Resource Assessment

Uinta Basin hydrocarbon resources have been the subject of numerous geological investigations. Some of the earliest work in oil sands was done by Covington in 1963 [32] and 1964 [33], describing and reviewing known deposits throughout Utah, including the Uinta Basin. In 1979, a comprehensive compilation of resources, including general extent of each deposit, location, stratigraphic position, lithology, size and grade was published in map [24] and report [34] formats. The most recent oil sands assessment was performed by Blackett in 1996 [35] using information contained in earlier reports; no

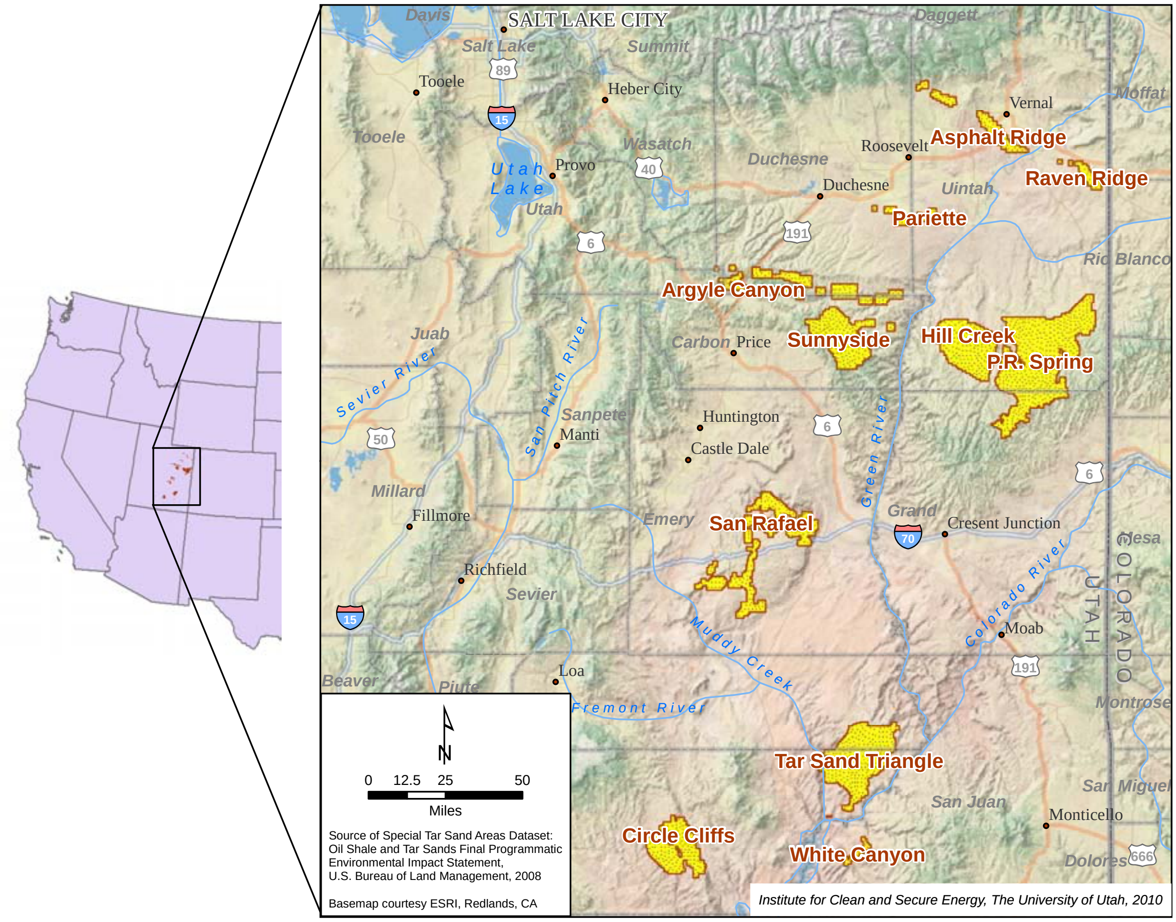

Figure 2.2: STSAs in Utah as designated by USGS.

Table 2-2. Uinta Basin in-place oil sands resource within designated STSAs; from Ritzma [24] and Oblad et al. [25].

STSA Deposit	Proven (million barrels)	Probable (million barrels)	Possible (million barrels)	Total (million barrels)
Asphalt Ridge - Whiterocks	487	481	305–345	1,273–1,313
Argyle Canyon-WillowCreek	–	–	60–90	60–90
Hill Creek	350	480	330	1,160
Pariette	–	–	12–15	12–15
P. R. Spring	2,500	1,200	550–1,100	4,250–4,800
Raven Ridge-Rim Rock	–	–	100–130	100–130
Sunnyside	1,800	2,200	1,200–1,850	5,200–5,850

new core data was included in this assessment. Blackett reviewed available information on 25 oil sand deposits in the Uinta Basin and concluded that most of the resource was found in four areas: Asphalt Ridge, P. R. Spring, Hill Creek and Sunnyside. As seen in Table 1 of Blackett [35] and in Table 2-2 above, the Asphalt Ridge deposit is estimated to contain 1 billion barrels OOIP, the P. R. Spring deposit to contain 4 billion barrels OOIP, and the Sunnyside deposit to contain 5 billion barrels OOIP. The remaining 21 areas are scattered along the northern and southwestern margins of the basin and contain smaller resources.

Dana and Sinks [36] describe the oil sands resource in the P. R. Spring area as saturated beds and zones that are "lenticular and discontinuous over both large and small areas." Based on cores that had been drilled, they note that "from one to twenty seven separate tar sand beds at least one foot thick of continuous saturation exist in the deposit, the thickest of which is 35 feet thick." In general, Utah oil sands are found in relatively shallow, thin, intermittent deposits.

2.2.2 Characteristics of Uinta Basin Oil Sands

The physical properties and elemental analyses of bitumens from the Uinta Basin are quite similar to one another but differ significantly from those of Canadian bitumens. A comparison of various properties of bitumens from the two areas is presented in Table 2-3. Uinta Basin samples have higher hydrogen content and about twice as much nitrogen but only one tenth as much sulfur. In an intrabasin comparison, Wood and Ritzma [37] observed that the most variable characteristic in Uinta Basin oil sands was the sulfur content, which varied from 0.19–0.62% by weight. The metal vanadium is significantly less in Uinta Basin bitumens, which is characteristic of lower-sulfur petroleum; nickel content is similar. Metal content is important because of the poisoning effects of these metals on catalytic refining processes.

Viscosity and penetration data show that Uinta Basin bitumens are notably more viscous than Canadian bitumens [38, 39]. Higher viscosity will affect the recovery process, particularly in situ processes where bitumen must be heated to higher temperatures before mobilization. High viscosity has also been shown to be a major contributor to lower recovery efficiencies in water-assisted recovery processes [25].

The fact that Uinta Basin bitumens have a lower specific gravity (e.g. higher API) and a higher molecular weight than the Athabasca bitumens suggests a different hydrocarbon structure [40]. Uinta Basin bitumens are significantly less aromatic and more naphthenic than Athabasca bitumens, resulting in consistently higher hydrogen contents and higher heating values. These properties result in higher processing yields for Uinta Basin bitumens [40]. Combined with the advantages inherent in lower heteroatom content, one might expect more favorable processing economics for Uinta Basin bitumen than those presently experienced commercially with Athabasca bitumen. The multiple reasons that Canadian oil sands have been exploited and those in Utah have not is discussed next.

Athabasca bitumens are of marine origin while Uinta Basin bitumens are believed to have originated from freshwater (e.g. lacustrine) aquatic life [41].

Heteroatoms include nitrogen, sulfur, oxygen, and any heavy metal.

Table 2-3. Typical bitumen properties for Uinta Basin oil sands compared to Canadian oil sands; from Bunger [41].

Property	Uinta Basin	Central-Southeast, Utah Athabasca, Canada
Carbon, wt%	85	83
Hydrogen, wt%	11.4	10.3
Nitrogen, wt%	1.0	0.5
Sulfur, wt%	0.5	4.7
Oxygen, wt%	variable	variable
C/H atomic ratio	0.60–0.65	0.65–0.70
Vanadium (ppm)	25	100–300
Nickel (ppm)	120	50–100
Viscosity, poise (77˚F at shear rate of 0.5 sec-1)	3–30 x 10^4	0.4–1.5 x 10^4
Penetration (0.1 mm) under 50 g load for 5 sec	<300	<300
Average molecular weight (VPO-benzene)	660–800	540–600
% volatiles @ 530°C TBP	50	60
Specific gravity (20/20)	0.985	1.0
API gravity	12	10
Carbon residue (Rammsbottom)	3–12	10–22
Asphaltenes (pentane)	4–16	16–26
Heating value (Btu/lb)	18,500	17,800

Oxygen content is highly variable and subject to error due to the possibility of oxidation during sampling and bitumen recovery procedures [41].

The penetration test measures vertical penetration in tenths of a millimeter of a standard needle into a bitumen sample [42].

After fully dispersing the sample in benzene, average molecular weight is measured using vapor pressure osmometry (VPO) [43].

The true boiling point (TBP) distillation method measures weight percent of low molecular weight, volatile organic compounds in the bitumen.

Ramsbottom Carbon Residue measures the tendency of a fuel to form carbon deposits under pyrolysis conditions at high temperature [44].

The pentane asphaltenes content is the weight of the toluene extract after the sample has first been extracted with pentane [45].

Bitumen viscosity is very high, generally greater than 10^3 cP [25].

2.2.3 Oil Sands Challenges

As with oil shale, the central economic challenge in extracting bitumen from Utah oil sands is the recoverable mass of marketable energy. Bitumen content in Utah oil sands ranges from 4.5–14.1% by weight. With ex situ production, a considerable expense is incurred in the processing and environmentally acceptable disposal of the remaining mineral matter. Additional expense is incurred in removing overburden. As noted previously in this section, Utah oil sands occur in thin layers, so a relatively larger amount of overburden must be removed per unit of oil sands processed compared to Canadian operations. These thin layers also mean that the economies of scale achieved by the enormous mining operations in Canada cannot be duplicated in Utah.

Two large oil sands companies in Alberta, Suncore and Syncrude, are mining ore bodies that are 98–164 feet (30–70 meters) thick and buried under 49–115 feet (15–35 meters) of overburden [46].

With in situ extraction, the lean-ore problem is reduced by leaving the rock in the ground and processing it there. However, in situ extraction is difficult due to the low grade, relatively shallow, thin, intermittent oil sands deposits in Utah, which lower the bitumen heating efficiency. A recent study by Gwynn [47] of oil sands in the P. R. Spring area of the Uinta Basin analyzed the frequency of thickness of oil sand beds. The highest frequency thicknesses were from 2.5–15 feet (0.76–4.6 meters) with one bed each at 73 feet (22 meters), 108 feet (33 meters), and 123 feet (37.5 meters). In Alberta, in situ production occurs in deposits with 984 feet (300 meters) of overburden, a low quality resource has a pay zone of 49 feet (15 meters), and a high quality resource has a pay zone of 115 feet (35 meters). Also, the Utah bitumen-saturated sands have varying permeabilities, ranging from 2 to 1,000 millidarcies (mD) [47], making flow to a production well difficult. Technical feasibility of in situ oil sands recovery has been demonstrated in Utah [28], but thus far economic feasibility has not.

For example, Gwynn notes the extreme differences in lithology from section to section in the P. R. Spring and Hill Creek tar sand areas [48].

A second challenge relates to the post-production upgrading steps that are required to produce a refinery-ready product from bitumen. Coking is the most common bitumen upgrading method in Alberta, and it produces a liquid fuel similar in properties to conventional oil [12]. However, yields from coking are only 60–70%. Higher yields together with the removal of sulfur, nitrogen and heavy metals are achieved through the secondary upgrading steps of hydrocracking or hydrotreating. Thus, bitumen upgrading for the scenarios in this report will require two steps, coking and hydrotreating.

A third challenge shared with oil sands is that of location. As noted in the 2007 ICSE report [12], the smaller oil sands deposits in Utah and the steep, mountainous terrain preclude the type of large-scale development seen in Alberta. Rather, Utah development "will result in smaller operations that may be less efficient for lack of economy of scale" [12]. Water availability and environmental concerns may also be challenges, even at the smaller 10,000 BPD scale of the oil sands scenarios in this report. However, in contrast to oil shale development, it is unlikely that there will be significant social and economic impacts on the area above and beyond those already occurring due to increased oil and gas drilling [12].

While lease availability is also a considerable challenge, this report assumes that the the requisite oil sands leases have been obtained for the selected sites. A brief summary of leasing challenges on both federal and state lands is found in Section 1.2.

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3 Government and Public Policy

3 Public Policy and Unconventional Fuels

From an energy policy perspective, the three most significant challenges facing unconventional fuel development are: (1) the absence of an effective pricing regime for GHG emissions, specifically carbon dioxide (CO_2), which adds uncertainty to development scenarios and to financing and investment decisions; (2) the lack of bi-partisan political will to develop a meaningful and long-term national energy strategy, including a coherent policy on utilization of domestic unconventional energy resources; and (3) the disconnect in public perception of current and future patterns of energy consumption and supply. All of these challenges are intertwined to some extent. For example, the public desire that risky oil development be limited (as seen in the wake of the 2010 Gulf Coast environmental disaster and in debate over Arctic resource development) conflicts with the desire for low gasoline prices, nurturing the lack of political will to acknowledge the need for far-reaching shifts in energy policy and consumption patterns. Similarly, the absence of effective carbon pricing or climate stabilization legislation facilitates the public disconnect between the patterns and costs of domestic energy consumption.

While the Energy Policy Act of 2005 decreed that unconventional fuels were "critical," the Act did not articulate where these fuels could best fit in the U.S. energy portfolio, nor has it generated any comprehensive, long-term policies.

Beginning in 2005, significant political effort and support were put into stimulating oil shale development on U.S. public lands, including the passage of the Energy Policy Act of 2005, completion of a foundational PEIS, finalization of federal oil shale leasing regulations, issuance of six initial RD&D leases for oil shale, and calls for a second round of oil shale lease submissions. Nevertheless, commercialization of the federal oil shale resource has yet to make substantial, measurable progress. Policymakers will need to utilize their political and economic tools more effectively if unconventional fuel resources are to be successfully commercialized in the future.

Oil price also has a strong impact on investment and development. The issue of price is addressed in the scenario analyses (Sections 6–9).

Law and policy may bear on unconventional fuel development in a number of ways through instruments such as leasing programs, species protection, and environmental safeguards. "Fiscal policy," the focus of this section, is another nexus of government action and resource development. The term "fiscal policy" refers to a set of rules concerning how local, state, and federal government revenue is derived from certain economic activities, such as the production of oil from oil sands and oil shale. Fiscal policy may advance a number of goals, including raising general purpose revenue for near future expenditures, internalizing various externalities of production, raising funds to mitigate socioeconomic impacts, and building a store of wealth to offset the loss of an exhaustible resource.

The importance of fiscal policy to an unconventional oil industry is suggested by estimates of "government take." The U.S. Government Accountability Office (GAO) has estimated government take to be between 40–50% for oil production in the Gulf of Mexico and between 50–60% for onshore projects [1,2].

Government take is defined as the proportion of payments to government in the (pre-take) cash flows from a project (revenues minus costs).

Because unconventional oil projects of the type analyzed in this report have little or no operational history in the U.S., fiscal policies are less developed than they are for conventional oil production. At the end of this section, developments in the fiscal system applying to the Canadian oil sands are reviewed as this unconventional resource provides the most important example of a fiscal regime and its evolution.

3.1 Fair Return and Economic Rent

This section discusses existing fiscal systems for securing a "fair return" in the U.S. and the application of these systems to oil production from unconventional sources in Utah. The two main issues involved are: (1) determination of the value of the unconventional oil resource, and (2) policy instruments available for realizing that value. The role of government in this context is to act as the broker of the resource on behalf of the owners.

In the case of unconventional fuel development on public lands, the public owns the resource in the ground (e. g. in situ). To obtain a fair payment on the resource, the correct point of valuation is in situ. However, in situ valuation is difficult, so valuation of the resource may take place after value has been added such that the product is marketable and there are a significant number of actual market transactions.

For valuation, it is not a matter of how much is produced but how much is in the ground as that is what the lessor is selling.

The technical term for the in situ value of the resource is economic rent. It would be difficult to overstate the importance of the concept of economic rent to the theory and practice of exhaustible resource taxation. It is repeatedly invoked in the discussions and subsequent policy decisions concerning taxation of the Alberta oil sands. More generally, economic rent is defined as "those payments to a factor of production that are in excess of the minimum payment necessary to have that factor supplied." [3] Another way to think of economic rent is that oil in the ground is worth less than oil extracted from the ground. The economic rent is the difference between the value of the oil upon extraction and the minimum economic cost of extraction (including a return on capital equal to that which would have been received on the next-most-attractive project, the value of the next best alternative use of the producer's resources, as well as all relevant capital and operating costs).

The "rent" in this term is unrelated to the rental payments discussed later in this section.

Thinking of a production process as a recipe, the factors of production are the ingredients. In the case of oil sands or oil shale, the factors include physical capital (buildings, machinery), labor, and the bitumen or kerogen in the ground. These factors are the inputs; the output is a high quality crude oil.

In the case of oil production, conventional or otherwise, the in situ oil resource is the factor of production that bears rent. Further, the entire value of the in situ oil resource is rent since, whatever the value of the resource, it is that much more than what is needed to make it available. Note that this is not the usual case. In the usual case, more of a factor is supplied when it can receive a higher price, less is supplied when it can only receive a lower price, and a tax levied on the factor reduces its availability. In the case of a rent-bearing factor, up to the entirety of the rent can be taxed away without affecting the availability of the resource.

The value (market price) of the oil in situ is the difference between its value (market price) ex situ and the minimum cost of transferring it from in situ to ex situ.

In principle, the resource owner, whether a government or private landowner, would offer financial terms to potential producers such that there is at least one producer who could produce and receive a rate of return on their investment slightly greater than that of their next-best alternative. If the terms allowed a higher rate of return, then the producer would still invest and produce, but the owner would receive less value for the right than could have been realized. If the terms allowed only a lower rate, then investment would not take place. For this reason, fiscal systems that take only the resource rent are not believed to discourage production.

Royalty and fiscal terms that take all and only the rent of the in situ oil maximize the resource owner's "profit" from the sale of its resource.

In practice, however, complications arise which make the pure rent tax system discussed in this section difficult to implement effectively. Perhaps most importantly, the rent of a resource such as an oil deposit cannot be known in advance with certainty. Rent is a function of the price of produced oil and numerous other factors such as technology which are exceedingly difficult to forecast accurately and precisely over the lifetime of an oil project. Even taxation strategies that appear in principle to meet this challenge might face political difficulties if they allow too much variation—under changing economic conditions, for example—in the government revenue derived from a project or industry.

3.2 Fiscal System Uncertainty

Unconventional oil projects carry a number of financial risks, including the stability of the fiscal system. Fiscal system uncertainty, like uncertainty in the future price of oil, creates uncertainty in a project's profitability. This uncertainty will diminish a project's value to risk-averse investors where risk aversion is defined as the preference for a more certain outcome with lower value than for an uncertain outcome with higher expected value.

Risk aversion appears to be the rule rather than the exception among investors, and people more generally. For example, people purchase insurance and firms purchase hedging instruments which are worth less on average than their cost; Canadian oil sands firms purchase hedges against the Canadian/U.S. dollar exchange rates and the price of oil when developing a major project.

The history of the Canadian oil sands industry suggests that fiscal regime uncertainty can have a stifling effect on private investment. This issue is outlined in the Alberta Oil Sands Royalty Guidelines [4] as part of a discussion on the motivation for a major revision of the oil sands royalty regime in 1997.

> "In 1993 the joint industry–government National Task Force on Oil Sands Strategies was launched by the Alberta Chamber of Resources to assess the technical, socio-economic, environmental and marketing aspects of oil sands development and recommend strategies to address these issues.
>
> The task force identified Alberta's ad hoc, project-specific royalty structure as a barrier to oil sands development. The ad hoc structure created uncertainty about what royalty terms would apply to future investments, because a Crown agreement establishing royalty terms had to be negotiated for each new oil sands development. In addition, since the royalty structure was not transparent, it was difficult for developers to evaluate investment plans.
>
> In its 1995 report, the task force outlined a comprehensive new approach for Alberta's oil sands industry. A key recommendation was that oil sands royalty should be established through legislation rather than individual Crown agreements. That is, the royalty regime should be generic: the same rules should apply in the same situations and the same standardized royalty terms should apply to all new OSR Projects. This generic approach to oil sands royalty would place all new OSR Projects on an equal footing. Standard royalty terms would create fiscal certainty and stability, and encourage oil sands investment."

OSR Projects = Oil Sands Royalty Projects.

Fiscal system uncertainty thus reduces the value of a project and stands, along with the price of oil, environmental policy, and technology, as a significant hurdle to developing unconventional fuels.

What does fiscal system uncertainty mean for an unconventional oil industry in the U.S ? It is relatively clear that the fiscal system applying to conventional oil production in the U.S. will not be an ideal system for unconventional production; unconventional production is a capital-intensive process taking place with resources bearing much less economic rent under current technology than

The still-evolving fiscal system governing the Alberta oil sands is quite different from the fiscal system governing conventional oil production in Alberta.

conventionally produced oil. A sizeable and growing unconventional oil industry in the U.S. would eventually stress the current system tailored for conventional resources and likewise call for a system better suited to the economic features of unconventional production. It is this uncertainty generated by the looming but unknown unconventional fiscal system that impacts would-be investors.

Unconventional production may entail environmental, public health, or socio-economic consequences (see Section 4) that call for some form of taxation. Consideration of these issues, in addition to that of obtaining a fair payment for public resources, may justify an overall fiscal system that taxes unconventional oil production more or less heavily than conventional oil production.

The term "more or less" is used here because an analysis of whether externalities associated with unconventional fuel production are net positive or negative is outside the scope of this report.

3.3 Fiscal Systems for Oil Production

Oil production in the U.S. is subject to: (1) royalty, rental and bonus payments to resource owners, and (2) an assortment of taxes to federal, state, and local levels of government. The set of policies that determine the level of these payments, often referred to as a "fiscal system," varies according to the resource being extracted, the method of extraction, and the location and type of owner of the resource. Fiscal systems for oil production in the U.S. are largely based on the value of the resource at the wellhead.

It is unclear how this concept might be applied or modified for the purposes of valuing unconventional oil production. In general, by their nature, unconventional resources are not as valuable in situ as their conventional counterparts, though value may be added through additional processing. For example, one of the scenarios analyzed in this report involves the mining of oil sands bitumen. The raw bitumen is then upgraded to a SCO having physical and economic properties of a light, low-sulfur crude. Based on the Canadian oil sands experience, a barrel of SCO might, on average, receive twice the price of a barrel of raw bitumen. If royalties and taxes are levied on gross sales, it becomes crucial whether the levies are based on the value of bitumen or the (much higher) value of SCO.

This situation is similar to the refining of conventional oil, in which the raw oil is processed into more valuable end-user products such as gasoline and jet fuel. The value added through conventional refining, however, escapes a direct royalty or production tax levy.

Upgrading can be regarded as pre-refining.

Canadian oil sands operators having both extraction and upgrading facilities have been allowed to choose whether to base their royalty payments on the price of SCO but deducting the capital and operating costs of the upgrader, or, alternatively, on the price of bitumen without deducting these costs. The idea is to levy the tax on extracted raw bitumen as the best directly marketable proxy for in situ bitumen. The price differential between SCO and bitumen will generally exhibit short-run fluctuations around the cost of producing SCO rather than bitumen. Thus, allowing deduction of these costs results in a tax base that is approximately the value of raw bitumen, whether raw bitumen is the product or SCO is the product. In this way, SCO and bitumen production are treated more equitably.

The price of bitumen is established according to Bitumen Valuation Methodology (Ministerial) Regulations published by the Alberta government [5].

3.4 Royalty and Tax Policy as a Tool

Policymakers have a number of tools available that can be and have been used to stimulate or curb certain types of economic activity. Because much of the oil and natural gas in the U.S. resides on public lands, tax and royalty arrangements that favor investment in exploration, development, and production of oil and gas are often deployed wherever it is believed that such activity is worthy of special incentives.

Whether it is desired to dampen production because of net negative externalities or stimulate it because of net positive externalities, moving the status-quo level of production can be accomplished through the use of fiscal policies (e.g. royalty and tax policy on oil production) that alter the price received by the producer for their product.

For a discussion on positive and negative externalities associated with unconventional fuel development, see Section 4 of this report.

Although both taxes and royalties can reduce the price a producer receives and increase total "government take," they are motivated by different purposes. Severance taxes are levied by the state on natural resources that are severed from the earth. For example, Utah levies severance taxes on all conventional oil and gas production within the state's geographical boundaries, not just production occurring on state lands. Unlike a tax, a royalty is a return to the owner of the resource.

This section outlines the various royalty, tax, and other payments that might apply to oil shale and oil sands development in the State of Utah under the existing fiscal system. Details about how these payments are applied to the scenarios in this report are discussed in Section 5.3.3.

3.4.1 Royalties, Bonus, and Rental Payments

Royalties, bonuses and rents are payments to the owner of a resource as compensation for its use. Scenarios analyzed in this report are located on both state and federal lands, so royalty payments are computed accordingly. Bonuses and rental payments are not specifically calculated for any of the scenarios. Instead, they are assumed to be covered by the capital cost of acquiring land. The details of existing royalty, bonus, and rental payments in the Uinta Basin are described below.

3.4.1.1 Federal, State, and Tribal Royalty Payments

Royalties are periodic payments, usually determined as a percentage of either the gross or net value of production. In some cases, royalty payments are made "in kind". The resource owner may then sell or store the oil. For the purposes of this report, it is assumed that royalty payments are made "in value".

"In kind" means that, in lieu of payments, the mineral owner receives a specified proportion of the volume of oil produced as a percentage of the oil's value. "In value" means that (1) payments are actually made in-value or (2) the revenue the mineral owner obtains from selling its royalty share is equal to what it would have obtained from payments in value.

In Utah, oil sands royalties on federal lands (managed by BLM) are governed by Title 30 of the Code of Federal Regulations [6] while oil shale/sands royalties on state lands (managed by SITLA) are governed by Rule 850-22 of the Utah Administrative Code [7]. BLM and the State of Utah differ not only in their unconventional fuels development philosophies but also in the terms they apply to commercial leases. The royalty rate applying to oil production on a BLM oil sands lease is 12.5% (1/8), the same as the standard rate levied on a federal onshore conventional oil lease. The royalty rate is applied to the value of the oil, which in the case of an arms-length contract is defined to be the gross proceeds from the sale, minus allowable transportation expenses [6]. The deductible transportation expenses are those incurred in moving the oil off the lease and to the point where the transfer to the buyer takes place [8]

Per statute, a lessee of federal lands may request that BLM lower the royalty rate.

An arms-length contract is a contract between two unaffiliated parties.

*For example, if sales proceeds are $80 per barrel and transportation expenses are $1 per barrel, then the royalty payment is 0.125 * (80 - 1) = $9.875 per barrel.*

Oil shale royalty rates applicable to BLM leases remain unsettled. Royalty rate rules that were finalized on November 18, 2008, were put on hold in early 2011 as part of a court settlement with numerous environmental groups. The new finalized regulations are to be published by November 18, 2012 [9]. In a lengthy discussion published in the Federal Register on November 18, 2008, BLM and public commentators discuss the "best" point of resource valuation (in situ, extracted but not processed, upgraded) and the "right" system of royalty rates to apply to this valuation, including the Alberta system for oil sands and Utah system for oil shale. In the 2008 royalty rules, "...BLM has chosen to adopt a royalty rate similar to Utah's by establishing an initial royalty rate of 5% during the first five years of production. Following five years of successful production, the rate will rise yearly by 1 percent until it reaches a level comparable to the royalty rate on onshore conventional crude oil" [10]. The 2008 rules also state that the royalty is to be determined at the point that products "are sold from or transported off of the lease area" with the caveat that "...it is premature to determine whether the Department will assess royalty on fuel used on the lease" [10]. Finally, the 2008 royalty rules note that, "As research and development of oil shale technology progresses, the BLM will have adequate time to reexamine and readjust royalty rates for oil shale production, either up or down" [10].

In contrast, oil sands and oil shale leases are available on SITLA lands with the royalty provision that during the first ten years of the lease, the royalty rate is 8%. SITLA may, at its discretion, increase the royalty rate by no more than 1% per year for each year after the first ten, up to a maximum rate of 12.5% [7]. However, in recent oil shale lease offerings from SITLA, this rule is not followed. Instead, the royalty rate is set at 5% for the first five years with the option to increase the rate thereafter by 1% annually up to a maximum of 12.5% [11].

The primary lease terms and leasing models under BLM and SITLA leases are nearly identical. Post-2005 SITLA leases, as well as BLM leases, contain a 10-year primary lease term. Both leases are renewable upon demonstration of commercially viable development. The federal lease provision states that the lessee must pay royalties on all products of oil that are sold from or transported off of the lease, suggesting that royalties are not charged on consumption of oil or oil derivatives on-site [12]. On SITLA leases, the royalty is applied to sales "of each marketable product produced from the leased substance and sold under a bonafide contract of sale" [7], which suggests that, similar to the federal leasing model, on-site consumption is not subject to royalty.

The exact statement in the federal code is "The royalty rate on all combined hydrocarbon leases or tar sand leases is 12 1/2 percent of the value of production removed or sold from a lease" [12].

It appears that once operators begin ex situ or in situ processing of oil shale/sands, they will be able to generate power for their process using energy from synthetic gas produced on-site free of royalty charges for the gas. This provision potentially negates the need for off-site sources of power to support commercial oil shale or oil sands development, which in turn affects the need for off-site infrastructure and grid integration. This approach is consistent with federal fluid mineral leasing, which allows on-site use of produced oil or gas free of royalty charges. In light of the extensive energy requirements for producing and upgrading shale- and sand-derived oil, this policy of waiving royalties for fuel consumed on site may need to be revisited.

The argument here is that the resources consumed on-site would have otherwise been produced in a more or less conventional manner and generated royalties. This argument assumes that these resources would have been produced in the future but for this activity.

Finally, with respect to tribal royalty rates, the federal government administers and approves oil leases on Indian lands, although much of the Uintah and Ouray reservation in the Uinta Basin (the Hill Creek Extension) is owned by the tribe in fee and is therefore not subject to federal administration or federal rules regarding royalty rates or lease terms. The standard lease term calls for a 16.67% royalty rate although the Secretary of the Interior may authorize a lower royalty rate when such rate "is agreed to by the Indian mineral owner and is found to be in the best interest of the Indian mineral owner" [13].

Royalty rates are also given for minerals other than oil and gas [13]. The rate is 10% for non-coal minerals. Nevertheless, this report generally assumes that in the absence of an explicit shale/sands provision, the policy for conventional oil applies.

3.4.1.2 Bonus Payments

When mineral extraction rights are awarded in a competitive auction conducted on behalf of a mineral owner, the "bonus payment" is the amount of the winning bid. Recent bonus payments received in competitive auction for SITLA oil sands and oil shale leases are shown in Table 3-1. As noted above, bonus payments are not specifically calculated in any of the scenarios in this report but are assumed to be covered by the capital allocated for mineral leasing and land purchase.

Land on which production facilities are located is purchased while operators typically lease rather than own the land from which they produce. The present analysis does not distinguish between leasing and purchasing.

Table 3-1. Leased acreage and bonus payments for winning bids on SITLA oil sands and oil shale leases; compiled from [14]. All payments are in U.S. dollars (US$).

Auction Date	Resource/Lease	Total Acreage Won	Total Bonus Payments	Bonus Payment per Acre
January 2003	Oil Shale	2,868	$3,150	$1.10
July 2003	Oil Shale	3,595	$7,189	$2.00
October 2003	Oil Shale	17,085	$19,653	$1.15
April 2005	Oil Sands	3,384	$25,900	$7.65
July 2005	Oil Sands	2,780	$116,740	$42.00
January 2006	Oil Shale	5,040	$8,059	$1.60
October 2006	Oil Sands	unknown	$558,432	unknown
January 2008	Oil Sands	1,903	$40,005	$21.00
July 2008	Oil Sands	1,138	$73,000	$64.10
October 2009	Oil Sands	794	$51,105	$64.40

In a world with risk-neutral—rather than risk-averse—investors and governments having symmetric information, the auctioning of rights to extract oil resources would be a viable, all-in-one method of collecting the ex ante economic rent of a deposit. In practice, however, bonus payments are just one of several components in a fiscal system that has evolved risk-sharing features for both parties to compensate somewhat for risk aversion and asymmetric information (e.g. the bidders in an auction may have a more accurate assessment of the value of the resource than the seller).

"Ex ante" is Latin, meaning "before the fact."

3.4.1.3 Rental Payments

Between the time the mineral rights are obtained and production starts, the producer will usually be responsible for annual rental payments, which are usually no more than $2 per acre. Like bonus payments, rental payments for the scenarios in this report are assumed to be covered by the capital allocated for mineral leasing and land purchase rather than specifically calculated.

On federal land, the annual rental rate for conventional oil and gas leases is $1.50 per acre for the first five years and $2 per acre for any year thereafter [15]. In a recent oil shale lease offering on SITLA land, the annual rental rate was $1 per acre [11]. To obtain costs on a per hectare basis, multiply the dollar amounts given here by 2.471.

3.4.2 Taxes

Oil production in the U.S. is subject to taxation at the federal, state and local levels of government. The most important of these are the state and federal corporate income taxes, state production (severance) taxes, and property taxes levied on capital equipment and on the value of reserves. Except for property taxes, all of these taxes are included in each scenario as described below. The actual property tax system is described below but, as a computational simplification, the property tax is implemented differently in the profitability analyses of later sections; see Section 5.4 for details.

3.4.2.1 Severance Tax and Conservation Fee

States can impose a severance tax on production taking place on lands within the state (federal, state, and private lands). States are not prevented from taxing production from lessees on federal lands, as explicitly stated in the Mineral Leasing Act of 1920 and affirmed by *Commonwealth Edison Co. v. Montana* [16]. States also can impose a severance tax on production from lessees of tribal land as settled in *Cotton Petroleum v. New Mexico* [17]. Additionally, tribes can and do impose their own severances taxes, so both state and tribal severance taxes may apply simultaneously to reservation production by nontribal lessees. As noted previously, the royalty interests of any landowner are not subject to the severance tax.

A severance tax, also known as a production tax, is a tax imposed on the extraction of natural resources in order to compensate the public for the permanent loss of natural resource wealth when non-renewable resources are depleted.

The severance tax is paid only on one's interest in the oil produced. In the case where the oil is produced from a lease, the lessor may retain a share in production as their royalty interest and the remaining share belongs to the producer as their working share. The developer pays the severance tax on their share of production (the working share), but not on the royalty share retained by the landowner. Under Utah law, all but private landowners are exempt from the severance tax on their royalty share [18]. For example, consider production on a federal lease in Utah where the federal royalty share is 12.5% and the state severance tax rate is 4% of the value of production. In this case, the developer pays a per barrel severance tax as defined in Equation (3.1):

$$ST = 4\% * [(100\% - 12.5\%) * oil\_value] \tag{3.1}$$

where ST is severance tax. The federal government owns the remaining 12.5% of production but is not responsible for a severance tax on it. If the state or a tribe (or tribal member) is the landowner, the result is the same. If the landowner is private, then the landowner is responsible for severance taxes; see Equation (3.2).

$$ST = 4\% * [12.5\% * oil\_value] \tag{3.2}$$

With the exception of oil produced on reservation lands by tribal owners, all oil production in Utah is subject to the state severance tax, which is levied on wellhead value. The tax rate depends on the product value. For product values less than $13 per barrel, the rate is 3% of product value. That part of product value exceeding $13 per barrel is taxed at a rate of 5% [18]. Exemptions include an allowance for any new well in the first six months of operation. An operator is also allowed to deduct transportation and "processing" costs from wellhead value for the purposes of determining the taxable value [19]. The methodology used to determine the wellhead value of unconventional fuels and the deductible processing costs is discussed in more detail in Section 5. The Utah severance tax is not currently imposed on production from oil shale or oil sands and, barring a change in state law, will remain unimposed until at least 2016 [20].

See ExxonMobil v. Utah State Tax Commission [21] for a discussion of oil valuation in this context.

"Processing" refers to removal of sediment and other contaminants from the oil immediately after it exits the wellhead [22].

For oil production on tribal lands by nontribal lessees, tribally-imposed severance tax rates may vary. The Ute Indian tribe, whose reservation covers 6,250 square miles (16,190 square kilometers) of the approximately 11,550 square miles (29,910 square kilometers) comprising the Uinta Basin, imposes a 10% severance tax on conventional oil and gas [23]; severance tax rates on oil shale and oil sands production are unknown. The tribe has published a mineral and mining development guide to aid potential developers [24].

Utah also levies a "conservation fee" equal to 0.20% of "taxable value," where "taxable value" is defined the same as for the severance tax [25]. The conservation fee funds the Oil and Gas Conservation Account, which is used to pay for the "plugging and reclamation of abandoned oil or gas wells or bore, core, or exploratory holes for which: (i) there is no reclamation surety; or (ii) the forfeited surety is insufficient for plugging and reclamation" [26]. It is assumed that the conservation fee is paid for in all scenarios regardless of whether or not any wells are involved in that scenario.

3.4.2.2 Corporate Income Tax

Federal corporate taxes are based on "taxable income," which is the difference between an operator's revenue and eligible deductions. Deductions usually include expensed and capitalized costs, either a percentage or cost depletion allowance, and state severance taxes. The corporate income tax, which is levied at both the federal and state levels, is therefore more akin to a tax on profits than the severance tax, conservation fees and standard royalties, which are closer to a tax on revenues. While both decreases in the price of oil and increases in the cost of production lead to a lower corporate income tax take, standard royalty, severance tax, and conservations fees are not at all sensitive to costs.

In the present analysis, revenue is derived almost entirely on oil sales.

Capital and operating costs are deductible items. Some costs can be "expensed" (deducted entirely) in the current year, while others must be deducted over time. Long-lived assets lose value, thus imposing a net cost on their owners. These costs are usually deducted according to a depreciation schedule. There are several depreciation schedules that vary according to how rapidly they indicate depreciation. It is generally to the operator's advantage to choose the schedule which implies the most rapid depreciation.

A depreciation schedule indicates, for tax purposes, the rate of depreciation over time.

The remaining value of an operator's oil deposit diminishes over time due to depletion of the deposit as production proceeds. Under federal tax law, operators are able to deduct as a cost an estimate of the value lost. There are two procedures for determining this depletion allowance: percentage depletion and cost depletion. To qualify for percentage depletion, operators must be "small independents," meaning they do not also have refining operations and do not produce more than 1,000 BPD. The percentage depletion allowance is 15% of adjusted gross income (income minus royalty, bonus, and rental payments) as a deduction from gross profits for determining taxable income [27]. The other procedure, cost depletion, is available to all operators. Cost depletion involves a recovery over time of the original cost of acquiring the oil property minus a salvage value at the end of production. The idea is that the difference in the value of the property at the time of leasing and at the time production ceases is a capital loss to the operator in the same manner that a machine depreciates over time.

For tax purposes, "property" here refers to ownership of the mineral rights. Separate rights (e.g. surface, timber, various mineral rights) are separate properties even if they pertain to the same general area on or in the earth.

The tax an operator owes is the product of the taxable income and the tax rate. The federal corporate income tax rate varies according to the level of taxable income, ranging from a low of 15% for the first $50,000 of taxable income to a high of 39% for that part of taxable income between $100,000 and $335,000. Table 3-2 shows rates for each category.

Table 3-2. Federal corporate income tax rates by taxable income; from [28].

Federal Taxable Income	Tax rate
0 - 50,000	15%
50,000 - 75,000	25%
75,000 - 100,000	34%
100,000 - 335,000	39%
335,000 - 10,000,000	34%
15,000,000 - 18,333,333	38%
> 18,333,333	35%

In addition to the federal corporate income tax, Utah imposes a state corporate income tax that is based on the federal taxable income. The Utah state corporate income tax rate is 5% for all levels of taxable income [29]; royalties are deductible for the purpose of the state income tax but federal income taxes are not.

3.4.3 Property Tax

Property tax systems can be distinguished according to the types of property subject to taxation, the methodology for arriving at the taxable value of these properties, and the tax rates that are applied to the taxable value to determine the total property tax owed. In Utah, both facilities and the value of the mineral right (e.g. the in situ value of oil) are subject to a property tax by various taxing entities within the state (e.g. counties, cities, school districts, etc.).

The value of the mineral right is centrally assessed by the Utah State Tax Commission using an estimate of the NPV of expected future operating profits from the production of the mineral. The Tax Commission obtains oil prices from a number of sources, including EIA, and averages them along with its in-house forecast. The averaged forecast is used to provide an estimate of future product prices. Accounting for the time value of money, the Tax Commission applies a discount rate to future net revenues. The discount rate is revised each year to reflect changes in the industry and financial markets. The discount rate applied by the Tax Commission was 12.46% in 2011 and 11.41% in 2012 [30,31].

For a discussion of NPV, see Section 5.2 of this report.

The discount rate is equivalent to the interest rate that is assumed when discounting cash flows. It represents the opportunity cost of capital.

Uintah County, the location of the oil shale and oil sands scenarios evaluated in this report, levies a property tax rate of 0.002781 and the Uintah County School District levies a rate of 0.006101. Additionally, a number of entities levy at much smaller rates that may or may not apply to scenarios in this report depending on their exact location.

In practice, implementing the mineral rights property valuation used by the Utah State Tax Commission was not compatible with the financial evaluation method used in this report. Instead, this report assumes a constant property tax is paid each year based on size of the capital investment in each scenario; see Section 5.4.3 for more detail.

3.4.4 State Tax Credit

In the recently completed 2012 General Session of the Utah State Legislature, a bill was passed that provides alternative energy development tax incentives in the form of tax credits, effective May 8, 2012 [32]. Both oil shale and oil sands are listed as forms of "alternative energy" in the bill. A project qualifies for the tax credit if it produces more than 1000 barrels per day of crude oil equivalent. For development projects with an economic life of less than 40 years, the tax credit applies for 20 years or for the economic life of the project, whichever is less. In this report, the time from commencement of construction to the end of production is 23 years, so a tax credit of 60% of "new state revenues" generated by the project applies. It is assumed that all tax revenue from the project is "new" tax revenue. If the tax credit exceeds the company's state corporate income tax liability, the unused part of the credit is added to the next year's credit and can be carried forward in this way for up to seven years.

"New state revenues" are defined in the bill as revenue from state corporate income taxes, sales and use taxes, and personal income taxes (based on the "new" income of those employed by the project).

To compute the tax credit, the three parts of new state revenues must be considered. The first part, state corporate income tax, is computed as described in Section 3.4.2.2. The second part, sales and use taxes, would have to be estimated based on assumptions of (1) the fraction of the total capital investment paid as sales tax and (2) the expenditures spent in-state. Because of the high uncertainty in what these fractions would be, sales and use taxes are not included in the tax credit calculations presented herein. The third part, personal income tax, is the tax revenue associated with wages and salaries. It is computed by estimating the total yearly labor earnings for a given scenario and multiplying by an effective tax rate of 2.8% based on earnings [33,34]. The state personal income tax rate is 5% before deductions while the effective tax rate accounts for deductions. The resulting tax credit is shown in Equation (3.3).

Earnings are defined as wages/salaries plus benefits.

$$C = r * (S_b + I + U) \tag{3.3}$$

where:

S_b = state corporate income tax liability before tax credit
I = personal income tax liability for workers employed by project in Utah
U = Utah sales tax revenues from project (neglected in this report)
C = tax credit
r = credit rate (e.g. 60%)
and S_b, I, and U are the "new" part of the total corporate, personal, and sales tax.

The tax owed to the state is then computed by subtracting the tax credit from the pre-credit tax liability,

$$\mathbf{S_a = S_b - C} \tag{3.4}$$

where:

S_a = state corporate income tax liability after credit.

If the credit in a given year exceeds the tax liability (S_b – C < 0), then the absolute value of (S_b–C) is added to the next year's credit.

The effect of the state tax credit on taxes paid for the ex situ oil shale scenario are tabulated in Section 5.4.3.

3.5 Evolving Fiscal System Applying to the Alberta Oil Sands

While existing and proposed fiscal systems in the U.S. provide useful information about the features that might be expected in future fiscal systems developed for unconventional fuel production, the Alberta oil sands industry provides a real-world technical and economic approximation to the hypothetical operations of this report. For this reason, the historical development of the fiscal system applying to the Alberta oil sands industry is complementary to the prior discussion of existing fiscal systems in the U.S.

Like U.S. operators, Canadian oil sands operators pay bonus bids and annual land rental fees to acquire and maintain their lease and royalties on some measure of the value created by production. They also pay property taxes, federal and provincial corporate income taxes, and sales tax. The province of Alberta receives four types of payments from oil sands development: (1) bonus bids totaling C$1.112 billion in 2008/09, down from C$2.463 billion in 2006/07 [35], (2) rental fees of C$3.50 per hectare per year with total rental collections of C$160 million in 2008/09, (3) royalties of C$2.973 billion collected in 2008/09, and (3) provincial corporate income taxes, which are in addition to the corporate income tax levied by the Canadian federal government. Royalties are deductible from Canadian federal income tax [36]. The Alberta government owns 81% of mineral rights but 97% of oil sands mineral rights [35]. The remaining rights are owned by private landowners [37].

Bonus bids are winning bids on the right to develop offered sites.

A hectare is 10,000 square meters, which is equivalent to 2.471 acres.

According to the Bank of Canada, the average exchange rate between C$ and US$ was 1.14 C$/US$ in 2009, 1.066 C$/US$ in 2008, 1.074 C$/US$ in 2007, and 1.13 C$/US$ in 2006.

Canadian policy with respect to oil sands projects has always been concerned with stimulating their development in light of high costs and special risks. However, as production costs have decreased and special risks associated with early-phase production have abated somewhat, concern has increasingly turned toward transferring greater value of oil sands production to the public [38]. Fiscal regimes bearing on oil sands projects can be divided into three periods. Although these periods correspond to specific and official rules governing royalties and taxes, they also correspond to three phases in the development of the industry.

3.5.1 Before 1997

Initial production in 1967 by what is now Suncor Energy Company marks the commercial beginning of the Canadian oil sands industry. This beginning followed decades of basic research and significant financial support by the Alberta government [39]. Following Suncor in commercial operation was Syncrude, which came online in July 1978. Both Suncor and Syncrude are said to be "integrated" mining operations, meaning they incorporate facilities for upgrading mined bitumen to SCO.

During this early stage of development, royalties were negotiated on a case-by-case basis with the Alberta government. Royalty rates ranged from 1% to 5% on gross revenue and 25% to 50% on net revenue [37]. Both Suncor and

Syncrude had royalty agreements that called for revenue calculations based on the price of SCO, rather than the cheaper bitumen. These agreements expired in 2009 and have been replaced with interim agreements that are in effect until 2016, at which point both Suncor and Syncrude will fall under the current royalty regime.

The commercial development of oil sands languished during the 1980s and through the early 1990s; see Figure 3.1. By the end of this period, the commercial oil sands industry consisted of Suncor, Syncrude, and a small number of in situ operations such as BP's Wolf Lake and ESSO's Cold Lake projects. Several planned projects, including the 70,000 BPD Alsands operation, were cancelled due to challenges that included the low oil prices of the period compared with the high cost of production and the uncertainty regarding the royalty regime [38,40].

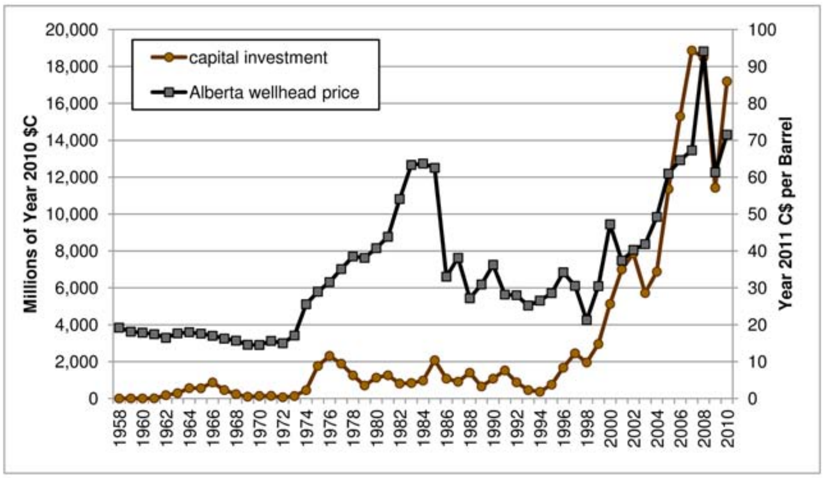

Figure 3.1: Capital investment in Canadian oil sands projects since 1958; from [41].

In 1993, the National Task Force on Oil Sands was formed with members of industry and government. The purpose of the Task Force was to determine what policies could be undertaken to accelerate development of the oil sands industry. In 1995, the Task Force delivered, and the Alberta government accepted, the recommendation that royalty provisions be uniformly applied rather than applied through individual agreements with the government. This new regime, known as the Generic Oil Sands Royalty Regime (GOSRR), became effective in late 1997.

3.5.2 Between 1997 and 2007

GOSRR remained in effect until 2007. The objective of the new system was twofold: (1) "To establish a single, clear and stable royalty regime that is applicable to all new investments in oil sands and facilitates development without the Province of Alberta having to provide grants, loans, loan guarantees, or become directly involved in any capacity other than resource owner" and (2) "To ensure that oil sands development in Alberta is generally competitive with other petroleum development investment opportunities around the world" [42]. This regime followed the recommendation of the Task Force in featuring a set of rules and royalty rates which applied "generically" to all new oil sands projects.

Under GOSRR, royalties were 1% of gross revenue until the project reached "payout." After payout, royalties were either 1% of gross revenue or 25% of net revenue, whichever was greater.

Payout is the point where cumulative revenue from the project equals cumulative costs.

The point at which a project reaches payout depends on project cost accounting. Among the allowable costs is a return on investment, which is set at the Government of Canada long-term bond rate (about 4% as of July 2010). Thus, reaching payout means recovering costs and making a conventional profit. This risk-sharing arrangement is meant to encourage and support new projects until they have returned their investors' costs plus a return. As of February 2009, 48 oil sands project were in pre-payout and 43 were in post-payout [35].

Under GOSRR, producers could choose whether to base royalties on bitumen production or SCO. If they chose to base royalties on SCO production, then the capital (including return on investment) and operating costs involved in upgrading would be deductible from gross revenue, but gross revenue would be based on the higher price for SCO. If they chose to base royalties on bitumen production, then capital (including return on investment) and operating costs for upgrading would not be deductible from gross revenue, but gross revenue would be based on the lower price of bitumen. Plourde notes that "all those who have had the right to choose have opted to pay royalties on bitumen production" [38].

3.5.3 Since 2007

By the mid-2000s, oil prices had risen well above the level that prevailed near the time of the 1997 royalty regime change. Oil sands production nearly doubled between 1997 and 2005, increasing from 192,493,000 barrels to 361,978,000 barrels [41] as seen in Figure 3.2. This rapid rise in production led to and supported a growing belief that the 1997 regime had already become outdated. In response, the Alberta government commissioned the Alberta Royalty Review Panel to consider alternative fiscal regimes.

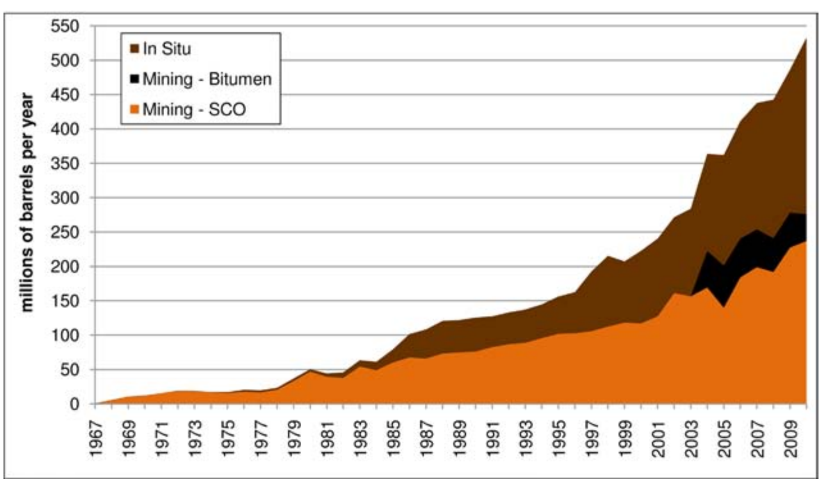

Figure 3.2: Alberta oil sands production by technology; from [41].

The Panel's findings, released in 2007, were stark, asserting, "Albertans do not receive their fair share from energy development" [43]. The Panel argued that the total "government take" from oil sands projects, in light of the then-present royalty structure and oil prices, was less onerous than projects in other parts of the world and could withstand an increase without significantly curtailing development. As stated in the findings, "the total government take (Alberta and Canada, taxes and royalties) can be increased with Alberta still remaining an attractive investment destination" [43].

"Alberta's bitumen has been worth 26% to 80% of WTI during [the four years ending 2009] recognizing the upgrading, refining and transportation costs in creating higher value products from oil sands crude" [36].

The Panel recommended a total government take from the oil sands sector of 64%, an increase over the 2007 total take of just under 50%. By way of comparison, in 1995 the National Oil Sands Task Force had identified 60% as the total take level appropriate to the needs of a fledgling oil sands industry. The Panel described the 64% level of government take as "more than reasonable for the production powerhouse the sector has become" [43].

Following the Panel's recommendation, a new royalty regime, the New Royalty Framework, was implemented. The New Royalty Framework retains the previous regime's differential treatment between pre and post-payout projects. For pre-payout projects, the royalty is still 1% of gross revenue provided that the price of WTI crude is less than C$56 per barrel. However, when the price of WTI is at or above C$56 per barrel, the royalty is 1% of gross revenue plus an additional 0.12308% of gross revenue for every dollar that the price of WTI is above C$55 per barrel but not more than C$120 per barrel. At C$120 per barrel and greater, the applicable royalty is 9% of gross revenue. In the post-payout period, the base royalty still applies, but it is supplemented with a royalty on net revenues. The royalty rate applying to net revenues is between 25% and 40%, depending on the price of WTI; the rate is 25% when the price of WTI is less than C$56 and increases by 0.23077% to a maximum of rate of 40% for every dollar that the price of WTI is at or above C$56 per barrel. Base royalties paid during the post-payout period are a credit against net revenue royalties (rather than a deduction in the calculation of net revenues). The Panel also recommended a severance tax with a similarly progressive tie to the price of WTI, but this recommendation was not accepted by the Government of Alberta. Canadian oil sands producers do not currently pay a severance tax [38].

The high royalty rates in the post-payout period (25–40%) apply to net revenue, not gross revenue, and thus are not directly comparable the 5%, 8%, and 12.5% federal/state royalty rates discussed in this section.

For Suncor, in situ projects became subject to the new regime beginning in 2009. However, Suncor's mining operations do not come under the new regime until 2016 due to an agreement with the Alberta government that pre-dated the New Royalty Framework (and its predecessor). Until 2016, Suncor's royalties will be based on bitumen prices instead of on SCO. Syncrude, which also had a prior agreement with the Alberta government, will become subject to the new regime in 2016 as well. All other oil sands producers are immediately subject to the New Royalty Framework [38].

3.6 Summary of U.S. and Alberta Fiscal Regimes Applying to Unconventional Fuels Development

Table 3-3 summarizes the fiscal regime applying to production of unconventional fuels from oil shale and oil sands in the U.S. and from oil sands in Alberta. The U.S. fiscal regime varies depending on the landowner (federal, state, private, tribal) and also differs significantly from the Alberta fiscal regime. Because the fiscal regime for unconventional fuels is not fully fleshed out in the U.S., some of the information in the table is taken from fiscal features of the conventional oil and gas industry as noted in Section 3.4 above. For information on actual bonus payments paid since 2003 in competitive auctions for SITLA oil sands and oil shale leases, see Table 3-1.

Table 3-3. Fiscal features of oil shale and oil sands development on private, SITLA, federal, and tribal lands within the State of Utah and of oil sands development in Alberta. All values are given in US$ unless otherwise noted.

For the information on taxes and payments applying to tribal lands in this table, it is assumed that the operator is a nontribal lessee. Activity on tribal lands by tribe members is untaxed by local, state, or federal government.

This table does not include the new state tax credit discussed in Section 3.4.4.

Fiscal Component	Private	Federal	SITLA	Tribal	Alberta
Royalty payment (paid to landowner)	Negotiated	12.5%	8% up to 12.5%	16.67%	Base royalty of 1–9% of gross revenue until payout, thereafter base royalty and 25–40% of net revenue but allowing base royalty as a credit. Actual rates tied to price of oil.
Bonus payment (paid to landowner)	Negotiated	Price paid for lease determined by competitive auction	Price paid for lease determined by competitive auction	Price paid for lease determined by competitive auction	Price paid for lease determined by competitive auction
Rental payment (paid to landowner)	Negotiated	$1.00–$2.00 per acre per year	$1.00–$2.00 per acre per year	$1.00–$2.00 per acre per year	Up to C$1.42 per acre per year
State severance tax (based on wellhead or "taxable" value)	3% for first $13/bbl, 5% for part > $13/bbl	3% for first $13/bbl, 5% for part > $13/bbl	3% for first $13/bbl, 5% for part > $13/bbl	5%	None
Tribal severance tax (based on wellhead or "taxable" value)	n/a	n/a	n/a	10%	None
State conservation fee (based on wellhead or "taxable" value)	0.2%	0.2%	0.2%	0.2%	None
State corporate income tax (based on taxable income)	5%	5%	5%	5%	10% for province of Alberta[a]
Federal corporate income tax (based on taxable income)	35%	35%	35%	35%	16.5%[b]
Property tax	~1% of NPV of property, including energy mineral & on-site facilities	~1% of NPV of property, including energy mineral & on-site facilities	~1% of NPV of property, including energy mineral & on-site facilities	~1% of NPV of property, including energy mineral & on-site facilities	~1.6% of value of on-site facilities but not of energy mineral in situ

References: (a) 41; (b) 42

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4 Competing Resource Costs and Challenges

4 Competing Resource Costs and Challenges Associated with Unconventional Fuels

Diverse public costs, or externalities, are associated with unconventional fuel development. This section addresses externalities and non-market costs that are not reduced to dollar terms, either because the costs fall upon third parties, or because of uncertainty associated with placing dollar values on the costs. These externalities must be viewed through two lenses—the actual nature and challenges of a specific public cost associated with unconventional fuel development, and the public perception of that cost. Public perception of a cost can impact the feasibility of development as much or more than the actual cost and may not correlate to the measurable scope of that cost.

Managing externalities requires not only an understanding of public perception and valuation of these resource costs; it also requires a more comprehensive public policy discussion of the trade-offs of energy resources generally. It is becoming increasingly understood by the public that all energy resources, including renewable energy such as wind and solar, entail costs and impacts. Understanding the relevant externalities of unconventional fuel resources and considering them in the context of the potential utility of such fuels is essential to successful policymaking and resource development.

This section reviews the concept of externalities and explores four commonly cited externalities related to unconventional fuel development: water resources and availability, land use impacts, air quality, and carbon management strategies. First, while the financial cost of water can be readily addressed in economic models, water acquisition represents an externality because water supplies are finite and water rights changes can impact the quality of life in rural communities, environmental values, and/or aesthetic values. Opposition to these types of changes can impact support for a particular project, potentially increasing transaction and permitting costs, which are externalities not reflected in the market price of water. Second, unconventional fuel development may render land incompatible for previous or planned uses such as conventional oil and gas development or habitat for endangered or threatened species during the time period of production and reclamation. Thus, land use also represents an externality. As with water, opposition to shifts in land use for large tracts of land can impact permitting costs, a situation currently faced by US Oil Sands [1]. A third externality, reduced air quality from industrial development, represents a cost shared by all those living in the airshed, not by purchasers of the SCO product. Degraded ambient conditions in the Uinta Basin pose a serious challenge to any unconventional fuels development proposal that further reduces air quality. Fourth, while CO_2 levels are rising in the atmosphere, it is unclear what impacts various levels of atmospheric CO_2 will have on the climate system and what costs those impacts will impose on various regions of the world over what time period. While specific emissions reduction targets and/or mechanisms for carbon pricing have been hotly debated, the debate has not yet resulted in concerted action. The externalities associated with carbon management hinder both energy policy and energy resource development.

4.1 Positive and Negative Externalities

While many economists believe that market prices generally provide appropriate incentives for producers and consumers, a commonly acknowledged exception to this rule occurs when production or consumption confers a cost or benefit to a party not directly involved in either. Side effects such as these are termed externalities because they are outside the scope of the (internal) cost-benefit considerations that take place between consumers and producers and which determine the level of production and consumption of the product at issue. Externalities result in an inefficient allocation of economic resources, whereas other types of side-effects result in the reallocation of resources from one user to another without loss of efficiency.

Oil production and consumption entail a number of side effects, not all of which are externalities.

Efficiency concerns the size of the economic pie, not how the pie is divided. An allocation of resources is inefficient if there exists a feasible alternative allocation of resources giving rise to a larger pie. Note that economic efficiency of an allocation implies little about its fairness.

With a negative externality, a cost rather than a benefit accrues outside the direct economic activity.

Pollution provides a classic case of a negative externality. Consider two commercial enterprises located near a river. The first is a steel manufacturer and the second is a riverfront resort hotel situated downstream. For the moment, assume that these two enterprises are the only users of the river. Recreational water activities form a large part of the resort's "product" and the value of this product. By extension, the commercial viability of the resort is inversely related to water quality. The steel manufacturer is contemplating additions at its existing location that will increase severalfold both its operating capacity and the byproduct waste that it releases into the river. If the two enterprises shared the same owner, then presumably the owner would appropriately consider the impact of the increase in pollution on the profitability of the downstream resort. In particular, if the gain in profit attending the upgrade is believed to outweigh the loss in profit to the resort, the owner would be expected to go forward with the upgrade in the absence of regulations or other constraints. If the additional pollution imposed a greater loss on the resort than the economic gain realized by the steel manufacturer, going forward with the upgrade would be a money-losing venture that a profit-motivated owner would avoid. Instead the owner might consider alternative plans such as modifications to the size and location of the new facilities. Provided the tradeoffs were correctly judged, the outcome would be economically efficient in any case. If the enterprises have different owners, then an efficient outcome may not be obtained, even if the owners have impeccable judgment. The crucial difference in the "distinct owners" case is that the impact to the resort of the increase in upstream pollution is not felt by the owner of the steel plant. If the additional production made possible by increased pollution creates more value than is lost downstream, then the "distinct owners" outcome is still efficient. If, however, the increase in pollution destroys more value downstream than it creates upstream, then the "distinct owners" case is no longer efficient.

The most efficient outcome is the one in which the net benefit from use of the river is maximized. In principle, third-party intervention (e.g. some form of government regulation) is not necessary to achieve the optimal outcome. According to the Coase Theorem, if the cost of negotiation (broadly defined) between the parties is low, then the parties will be able to reach an agreement that coincides with the most efficient outcome [2]. For example, if the steel manufacturer destroys more value downstream than is made possible by its pollution upstream but is able to partially abate or relocate the pollution at a cost that is less than the loss to the resort owner, then the incentive exists for the resort owner to fund such an action, and the outcome is once again efficient.

Here, efficiency is determined by a metric on outcomes that adds with equal weight the simple net benefits of each outcome across all affected parties and ranks outcomes as more efficient that have higher total net benefits. Efficiency measured in this way does not reflect the distribution of benefits and costs among affected parties, only their total.

However, as Coase himself made clear, in many realistic settings the costs of such negotiations will be prohibitive [3]. The most important barrier to successful negotiation is probably the high number of actual users of the resource, creating informational and strategic difficulties for negotiation. As the number of polluters and adversely affected users increases beyond a few, the likelihood of successful negotiation decreases rapidly. In these cases, some form of regulation is called for. Tax policy often serves, or is recommended to serve, as a vehicle for carrying out the goals of such regulation. Recent proposals to tax CO_2 emissions illustrate this role. The limited success to date of international efforts to stabilize or reduce CO_2 also illustrates the potential difficulties of negotiation.

4.1.1 Energy Security and Unconventional Fuel Development

Support for unconventional oil development rests on the balance of the difference between its social benefits and social costs. The difference, the net social benefit, need not be large, only positive. Although domestic fossil fuel production entails certain negative public health and environmental externalities (see Sections 4.2–4.5), these must be weighed against possible positive externalities.

Social costs and benefits are the sum of private costs and benefits and externalities.

One positive externality that is widely used as an argument for unconventional fuel development is the increase in energy security resulting from increased domestic production. This sort of benefit would be obtained if, for example, increased domestic oil production reduced the share of world oil supply in the control of countries whose leaders might consider a cutoff of supply such as occurred in the oil embargo of 1973. Increasing the share of world oil supply from domestic sources and from U.S. allies would reduce the effectiveness of "oil as a weapon." As discussed in the following paragraphs, while this view has a degree of merit, the consumption of oil, whether domestic or imported, entails risks to the macroeconomy.

The key issue in energy security arising from oil consumption is not the high proportion of oil imported from "unfriendly" countries but that oil consumption is such an integral part of the economy in the first place.

Macroeconomy refers to the economy as a whole rather than regional or local markets.

One thing an unconventional oil industry on the scale envisioned in this report will not do is lead to perceptibly lower oil or gasoline prices. Regions that produce large amounts of oil do not generally enjoy lower prices for oil or for oil products. This is because oil produced domestically, like oil produced overseas, is priced in an integrated oil market in which oil prices are largely determined by the worldwide supply and demand for oil.

The nature of the world oil market has implications for energy security. Since oil "is a commodity priced on world markets" [4], the U.S. would still be vulnerable to oil price fluctuations even if it produced all the oil it consumed. "A supply reduction in the Middle East would raise prices of domestic oil just as readily as it raises prices of imported oil" [4]. This view is corroborated in a 2010 report by Brown and Huntington [5]:

> "Because oil is fungible and its price is determined in an integrated world market, domestically produced oil is subject to the same global oil price shocks as imported oil. A disruption of foreign oil supplies would mean higher oil prices in the United States, even if it were importing no oil from the country whose production was disrupted. Rising oil prices elsewhere in the world would divert secure supplies from the United States to other markets, and the United States would see the same oil price gains that prevail on world markets. Because no oil supplies are secure from price shocks, the increased consumption of either domestic or imported oil has the potential to increase the economy's exposure to oil supply shocks."

Oil security concerns the vulnerability of the U.S. to oil price (or oil supply) shocks. This vulnerability is suggested by the positive temporal correlation between oil prices and performance of the broader economy (measured by gross domestic product or GDP). James Hamilton, a noted scholar of the relationship history between oil and the U.S. macroeconomy, has pointed out that all but one of the eleven U.S. recessions since World War II immediately followed a period of rapidly rising oil prices [6].

Vulnerability to oil shocks is a function of two circumstances: (1) the sensitivity of the U.S. economy to an oil shock, should one occur, and (2) the likelihood that one occurs. As the correlation between oil price shocks and recessions suggests, the sensitivity of the U.S. economy to oil price shocks is considerably larger than what is readily explained by reference to transfers of payments from the U.S. to foreign oil producers. The particular pathways through which oil price increases lead to large losses in overall economic activity (GDP) are not well understood and are an active area of economic research. The 2010 Brown and Huntington study states, "Whatever generates the strong impact of oil supply shocks on U.S. economic activity, the economic losses from such shocks are well beyond the possible increase in costs that any individual might expect to bear as part of an oil purchase... Because the exposure of the economy to the GDP losses associated with supply disruptions increases with oil consumption, individual decisions to increase oil consumption generate externalities" [5].

Domestic production in no way ensures domestic supply in the event of a "supply shock." Domestic oil producers, which include international oil firms, would be under no obligation to sell oil preferentially to the U.S. at less than the going world price.

The conclusion one can draw from the above study and from several other well-respected sources [7,8] is that, for a given level of oil consumption, it is less costly to energy security to consume domestically-produced rather than imported crude. The difference, which is called the energy security premium is rather small: \$2.17 per barrel in 2008, rising to \$2.52 in 2030. But it is important to emphasize that any barrel of oil consumed, wherever it originates, generates an an absolute expected cost to energy security on account of the integration of the world oil market and the contribution of each barrel of oil consumed to the sensitivity of the macroeconomy to oil price increases. Thus, two ways of increasing energy security would be (1) to reduce consumption through improvements in fuel efficiency, and (2) to increase the share of domestic oil in total oil consumption while not increasing total consumption of oil.

The energy security premium is the amount per barrel society would be justified in paying in order to reduce consumption of that barrel (imported or domestic).

The impact of increased domestic production of unconventional fuels on energy security would be limited for two reasons. First, the potential further additions to oil supply from the U.S. or its allies is limited, with supply from the Alberta oil sands being the most important of these sources. The two largest unconventional fuels scenarios analyzed in this report have production levels of 50,000 BPD, about one-quarter of 1% of U.S. petroleum consumption and less than one-tenth of 1% of recent worldwide petroleum supply [9]. Even a domestic unconventional oil industry producing as much as a few million barrels per day would have only minor effects on world oil prices, the ability of the U.S. to absorb an oil supply (i.e. price) shock, or the likelihood of such a shock occurring. Second, to the extent that domestic oil production is successful at lowering or stabilizing world oil prices, it is also likely to increase oil consumption and the share of oil consumption in the consumption of all goods and services, potentially increasing vulnerability to oil price shocks. U.S. oil dependence stood at about 50% in 2010, down from the 60% that was more typical of the previous decade; U.S. oil imports have decreased, domestic oil production has increased, oil exports have increased, refinery gains have increased, and total U.S. oil consumption has decreased [9]. The 2005 RAND report on oil shale notes that oil shale production of three million BPD in the U.S. "... would likely cause world oil prices to be lower than they would otherwise be. Oil consumers in the United States would benefit from these lower prices, although producers of non–shale oil supplies, including those operating in the United States, would be worse off. In addition, consumers abroad would benefit from lower oil prices, which could be in the economic and political interests of the United States. These global benefits are not considered in the narrow calculations conducted by private firms when assessing the profitability of shale oil production" [10].

EIA defines oil dependence as the share of net oil imports (gross imports minus gross exports) in total U.S. oil consumption [11].

In 2010, the countries from which the U.S. imported the most oil were: Canada (25%), Saudi Arabia (12%), Nigeria (11%), Venezuela (10%), and Mexico (9%). The values given are percent of net imports [12].

4.1.2 Job Opportunities and Unconventional Fuel Development

Another oft-cited positive externality associated with unconventional fuel development is that such activity will benefit the U.S. in terms of job opportunities and private and public revenue. Estimates of the magnitude of such benefits cannot be given precisely as they depend on the particular state of the economy during the time of production. For example, if the rate of unemployment of labor happens to be low when large scale development of unconventional oil takes place, then in large part the employment effects amount to shifting employment from one sector to another, rather than creating net new jobs. Of course, the fact that employed workers leave their current jobs for positions in the unconventional oil industry suggests that those movements are improvements on their current employment, but the actual gains are net, not gross. As noted in the 2005 RAND report:

> "While oil shale production will clearly increase employment in areas around production facilities, the effect on employment in the economy as a whole is uncertain. National employment and unemployment levels are affected by macroeconomic factors, including tax policy, the monetary policy of the Federal Reserve Bank, and the net change in national employment rates will depend on reactions in other parts of the economy. If investment in oil shale does not displace investment in other parts of the U.S. oil industry or in other sectors of the economy, the economywide employment impacts of shale oil production might approximate the estimates provided above. If, on the other hand, oil shale production results only in the reallocation within the United States of a given amount of capital to a set of slightly more productive investments, the gains in employment predicted above could be partially offset by declines in other parts of the economy" [10].

The nascent development of the Bakken formation in North Dakota provides an illustration that is rather typical of the early stages of fossil-fuel development:

> "North Dakota unemployment is the lowest in the nation, but high wages from the oil and gas industry has systemic impacts. Wage inflation is beginning to take root as it is difficult for stores, shops, and restaurants to keep workers given the opportunities in the petroleum sector. The entire range of services required to support the oil boom are in short supply. Hotels in petroleum producing regions of North Dakota are booked two to three years out and every apartment is rented. Make-shift housing such as campers and RVs are commonplace. Many oil companies operate their own "man camps" where employees eat and sleep while they are working. A challenge for the state is to address the requirements for expanded infrastructure and related services while at the same time addressing the financial risks of an economic downturn should the rising production prove unsustainable" [13, internal references omitted].

The phenomenon of inflation arising from competition for labor is true for other resources as well. To the extent that capital and other resources are fully employed in other activities at the commencement or during the course of development, they are shifted from one activity to another (although the fact of the shift suggests that a net gain is made in pursuing the new activity vis-a-vis the old). Another way to state this issue is that unconventional fuel development has opportunity costs, where those costs measure the value of the opportunities foregone when capital, labor, and other resources are used in the unconventional fuel industry rather than in their next most productive alternative. When unemployment rates (of labor, capital, and other resources) are high, then the value of forgone opportunities is low and much of the gross gain in employing these resources in the new industry is net gain.

Section 10 estimates employment and income impacts for the ex situ oil shale and oil sands development scenarios under the assumption that the state of the economy is such that no "crowding out" of other industries takes place.

4.2 Water Resources and Availability

Water is an increasingly scarce resource, with competition intensifying as western states grow and development pressures swell. Competition for water is particularly acute in the regions where domestic oil shale and sands resources are found. Precipitation at Bonanza, Utah, near Utah's richest oil shale resources, averages under ten inches annually [14], and oil shale-bearing portions of Colorado and Wyoming are similarly arid. Stream flows are highly variable, fluctuating widely year-to-year and season-to-season; flows peak with spring snowmelt and fall by as much as 80% or more during winter.

The White River, flowing from Colorado into Utah before merging into the Green and eventually the Colorado rivers, is at the center of discussions over water for unconventional fuel development. The White River flows along the edge of the Piceance Basin and through the heart of the Uinta Basin—the two richest oil shale basins in the world—as shown in Figure 4.1. It is therefore not surprising that the river has been dubbed the "first-choice source of water" for oil shale development within Utah [15].

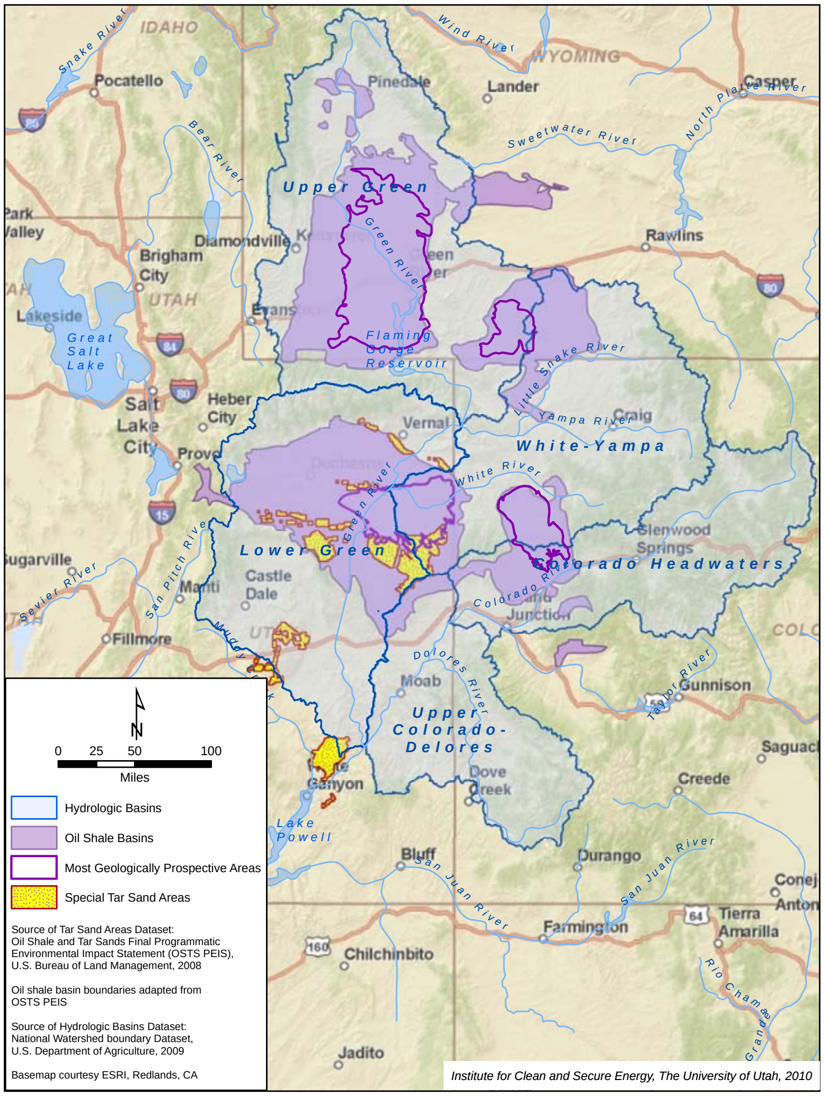

Figure 4.1: Hydrologic basins of the area comprising the Green River Formation.

4.2.1 Water Requirements for Oil Shale and Oil Sands Development

While development of oil shale and oil sands will require water, the present reality is that no one is sure how much water. Water use will depend on the size of the industry that develops and the technologies deployed. Which source or sources best meet these demands will depend on facility location. A recent report from the U.S. GAO estimates water use for an ex situ oil shale operation to be in the range of 2–4 barrels of water per barrel of oil produced and for an in situ operation to be in the range of 1–12 barrels of water per barrel of oil produced [16]. Such estimates, however, are only as good as the assumptions upon which they are based—many of which are outdated, untested, and unrealistic. An ICSE assessment indicates use of 1.5–3.0 units of water per unit of oil produced [17].

The specifics of the water challenges associated with obtaining water for oil shale or oil sands development will depend upon how industries develop and whether unconventional fuel development supplants or supplements other water uses. Water re-use and recycling, common in the conventional hydrocarbon production sector, can reduce the net demand and will undoubtedly be incorporated into facility operations if unconventional fuel production occurs on an appreciable scale. However, these measures do not eliminate the water demand challenges associated with commercialization of the oil shale and oil sands resources.

For conventional mining and surface retorting of oil shale, water is needed for dust control during materials extraction, crushing, transport, storage and disposal, cooling, reclamation and re-vegetation, upgrading, and various additional uses such as site sanitary waste systems, emergency fire suppression, and environmental controls. Ex situ oil sands production requires water for the extraction process and for ancillary uses associated with mining, upgrading, and reclamation as listed for oil shale. Depending on the extraction method used, in situ production may increase or decrease process water requirements over ex situ production. All in situ methods require water for post extraction cooling of condensable products, product upgrading, environmental control systems, power production, and post-production site reclamation and revegetation.

4.2.2 Water Rights in the Uinta Basin

While a 50,000 BPD unconventional fuel industry would require only a small fraction of the water within the White River or Green River systems, surface water and groundwater resources throughout the region are, with few exceptions, fully appropriated. Hence, development will require reallocation of water rights, which in turn involves direct costs, transaction costs, and social costs that will be felt by the local community. Water reallocation represents an externality because water supplies converted from irrigation or other uses to industrial purposes affect a change in the quality of life for rural communities that are not reflected in the market transaction. Water right changes may also impact environmental or aesthetic values. Opposition to these types of changes can impact support for a particular project, which may in turn increase transaction and permitting costs. Finally, in addition to future unconventional fuel development, continued population growth and proposed natural gas development will increase demand for finite water resources. With water supply largely fixed, the price of water will increase and some users will be priced out of the market. Non-consumptive uses such as in-stream habitats, aesthetic values and recreational uses will face increasing competition from consumptive uses. The collateral effects of these potential shifts in water use and pricing represent important model externalities.

A 2001 map showing new water right availability, "Water Rights Area Map with Policy by Area," is available from the Utah Division of Water Rights [18] and is reproduced and discussed in a 2010 ICSE report [19].

Competition for western water is not a new problem; water disputes date to pre-statehood mining camps. The doctrine of prior appropriation emerged from these camps as a means of resolving competing claims to water rights. The prior appropriation doctrine allows for the transfer of water rights to more economically profitable uses, provided that transfers comply with applicable regulations and do not result in injury to other water users. Recognizing that water development projects are often expensive, can take many years to complete, and can be difficult to finance if priority is not protected, prior appropriation allows water users time to develop their water rights. Provided

Prior appropriation is most commonly encapsulated by the adage, "first in time, first in right" [20].

appropriators act with the required diligence, the priority date normally relates back to the date upon which the applicant filed to appropriate water, even if it takes years to develop the right [21,22]. The date for demonstrating beneficial use, or "perfecting" a water right, can be extended provided that the applicant demonstrates diligent effort to develop the resource [23].

In Utah, the most promising sources of water supply represent underdeveloped state and tribal rights that are senior to many existing uses [19,24]. The exercise of these rights could displace existing, junior water users and lead to dramatic shifts in existing patterns of water usage. For water users in eastern Utah, these challenges and costs are complicated by the valid but unsettled nature of the Ute Indian Tribes' claims to vast quantities of water from the White, Green, and Duchesne river systems. These claims are senior to almost all other claims within the Uinta Basin and could support—or compete with—unconventional fuel development. No matter how these rights are developed, they threaten to displace what were previously considered secure water rights and uses.

The Ute claims are not legally settled in terms of the amount of water that can be withdrawn and used, the place of use, the season of use, and the nature of use as well as the right to convey tribal water rights. For a discussion of Indian reserved rights claims and their potential impact on unconventional fuel development, see Ruple and Keiter [19].

Another uncertainty with respect to water supply involves Colorado River tributaries. Although a complex body of law exists to allocate water among the states within the Colorado River Basin, the law remains largely unsettled with respect to apportionment of individual interstate Colorado River tributaries such as the White River. Specifically, it is uncertain how much of the White River Colorado can consume, and therefore, how much water will be available in Utah.

For a discussion of interstate allocation of surface water under the Colorado River Compact and Upper Colorado River Compact, see Ruple and Keiter [19].

4.2.3 Water Availability

In addition to these water use and water rights uncertainties, water availability is constrained by quantitative and qualitative water requirements under the Endangered Species Act (ESA) [24,25]. The major river systems near prospective development areas for oil shale and oil sands are home to four federally protected fish, which indirectly lay claim to water for habitat protection because the ESA protects not only these four species of fish, but also their habitat [26]. There are five classes of activities that threaten these fish and could run afoul of the ESA: (1) reduced quantity and quality of seasonal back-water habitat used during spawning and migration; (2) reduced availability of nursery and rearing habitat; (3) reduced sediment transport capacity and associated changes in river habitat and productivity; (4) created habitats favoring non-native fishes that compete with endangered native species; and (5) reduced future flexibility in stream flow management resulting from increased consumptive use [27]. Water development required for unconventional fuel production must consider how the ESA and evolving instream flow protection requirements will impact water availability, even if these considerations are not captured by economic models.

Demands for water present three significant policy issues associated with the public costs of evaluating and committing water resources to unconventional fuel development. First, assuming new sources of supply are not discovered, which existing water users will be displaced by unconventional fuel development? Second, what are the acceptable economic and public costs of reallocating water from agricultural or other use to unconventional fuel development? Third, can those costs be reasonably predicted into the future and at what production levels are they sustainable should unconventional fuels industries be successfully launched? Policies intended to encourage the development of an unconventional fuels industry will need to accommodate national energy and environmental objectives, as well as transparency, innovation, and adaptation as knowledge of the technologies and their associated impacts increases. Collaborating across industry-policymaker-stakeholder lines to clarify water availability and to evaluate competing resource values in the context of a federal energy policy will be essential elements of unconventional fuel development within the intermountain west.

One action that could bolster collaborative planning efforts would be apportionment of the White River. Currently, there is no formal agreement regarding how much water Colorado must allow to flow to Utah from Colorado. Apportionment would significantly improve water availability projections in both Colorado and Utah by clarifying how much water can be developed in Colorado and how much must reach Utah. Another such action would be settlement of the Ute Tribe of Indian's reserved water rights claims [19], which would help clarify the relative value of competing water rights. Together, these efforts could yield more accurate valuation of water resources and allow markets to reallocate the water rights critical to commercial oil shale and oil sands development. While prior efforts to resolve both issues have been unsuccessful, energy production may provide an incentive to move forward.

4.2.4 Cost of Water

The economic value of water varies widely according to several factors, including location and use. Because of these differences, the price paid for water in one area may not accurately reflect the value of water elsewhere. Furthermore, water markets are often underdeveloped, yielding limited information regarding the price of water and the determinants of value. Despite these uncertainties, five factors central to water right valuations are:

1. Water availability - Water supplies in most areas are fully appropriated. Securing additional water supplies is often difficult and involves transferring rights from existing users. If new water rights remain available, the price of existing water rights will be constrained by the costs of developing new supplies (e.g., drilling, pumping, and storage).
2. Water quantity - The size of the conveyance can influence the per-unit costs.
3. Water quality - Where water quality is a constraint, prospective purchasers must either identify higher quality sources or include treatment in project costs. Higher quality water is generally more valuable than degraded water.
4. Water right characteristics - The right to use water is reflected in a state-issued water right, as shares in a water company, or in a water service contract. The legal characteristics are important determinants of value. Early priority dates are generally more valuable than junior rights. Annual quantities, seasons and rates of diversion, and current use all affect prices.
5. Water right transferability - Legal requirements can limit the quantity, use, and location available for a water right transfer. Special requirements often apply when the point of diversion or place of use is moved to a point outside of the original basin. In some instances, inter-basin exchanges may be prohibited.

A mature water market has not developed within the Uinta Basin. Markets appear to be informal in nature and no water rights are currently advertised for sale. By comparison, during 2011, water rights offered for sale within Utah averaged approximately $6,000 per acre-foot [28]. Where new water rights are available from the State, no per-unit costs are charged. Acquisition of water rights, regardless of their source, may be subject to transaction costs far in excess of the cost of the water itself.

An acre-foot is equivalent to 1233 cubic meters.

Water produced as a byproduct of conventional hydrocarbon production may represent a potential source of supply, as could saline groundwater [17]. The cost of desalination depends on factors such as the treatment process used, the quantity of water being treated, the initial salinity level of the water, the existence of other contaminants that may need to be addressed, the level to which the water must be treated, the cost of electricity, and the cost of residual brine disposal. Brine from oil field operations can be treated at a cost of approximately $1,300 to $2,600 per acre-foot [29,30]. If permitting challenges can be overcome and costs are not prohibitive, these often ignored water resources could be of value to oil shale or sands producers.

4.3 Land Use Impacts

Commercial oil shale and oil sands development depends on access to resources. In Utah, looking at the most prospective 25 GPT oil shale resources, the federal government (BLM) controls approximately 52% of the resource, private interests control an estimated 17%, and SITLA controls roughly 9%, with the remainder of the resource primarily under tribal control [31]; see Figure 4.2. Ownership is fragmented, with many 640-acre (259-hectare) state parcels surrounded by federal land. Fragmented ownership and divergent policies complicate leasing and efforts to access resources. Different management objectives affect development, and all of these considerations are external to the analyses performed in this report.

While a 2011 ICSE report [32] utilizes slightly different assumptions and methodologies to measure resource control, it also concludes that a broad array of interests control oil shale resources within Utah and that entities are likely to adopt different development objectives.

4.3.1 Colocated Resource Management

Coordination and collaborative planning will be required to adequately manage the development of oil shale across jurisdictional boundaries and in conjunction with other colocated resources. Within the most prospective oil shale area as defined in BLM's 2007 Draft PEIS, 94% of the land administered by BLM in Colorado is already leased for oil and gas; in Utah and Wyoming, those numbers are 83% and 71% respectively [33]. According to DOI, "commercial oil shale development . . . is largely incompatible with other mineral development activities and would likely preclude these other activities while oil shale development and production are ongoing" [34]. Compatibility will depend on the scale and density of development; with careful planning, it may be possible to proceed with some level of concurrent resource development. The potential conflict should not be underestimated. As of early 2011, more than 24,000 new wells had been approved or were pending approval within the Uinta Basin—roughly half of which appear to be in highly desirable oil shale areas [32]. The extent of resource colocation is illustrated in Figure 4.3.

While the Multiple Mineral Development Act [35] provides some guidance regarding conflicts between leasable and locatable minerals, it does not apply to conflicts arising between persons interested in different leasable minerals such as unconventional resources and oil or natural gas [36]. Potential unconventional resource lessees must therefore rely on BLM's case-by-case resolution of disputes.

With respect to oil sands, DOI has not quantified potential conflicts between oil sands production and conventional hydrocarbon production within the eleven STSAs shown in Figure 4.3. Evaluating the scope of these potential conflicts is problematic as some of the lands in question may be subject to

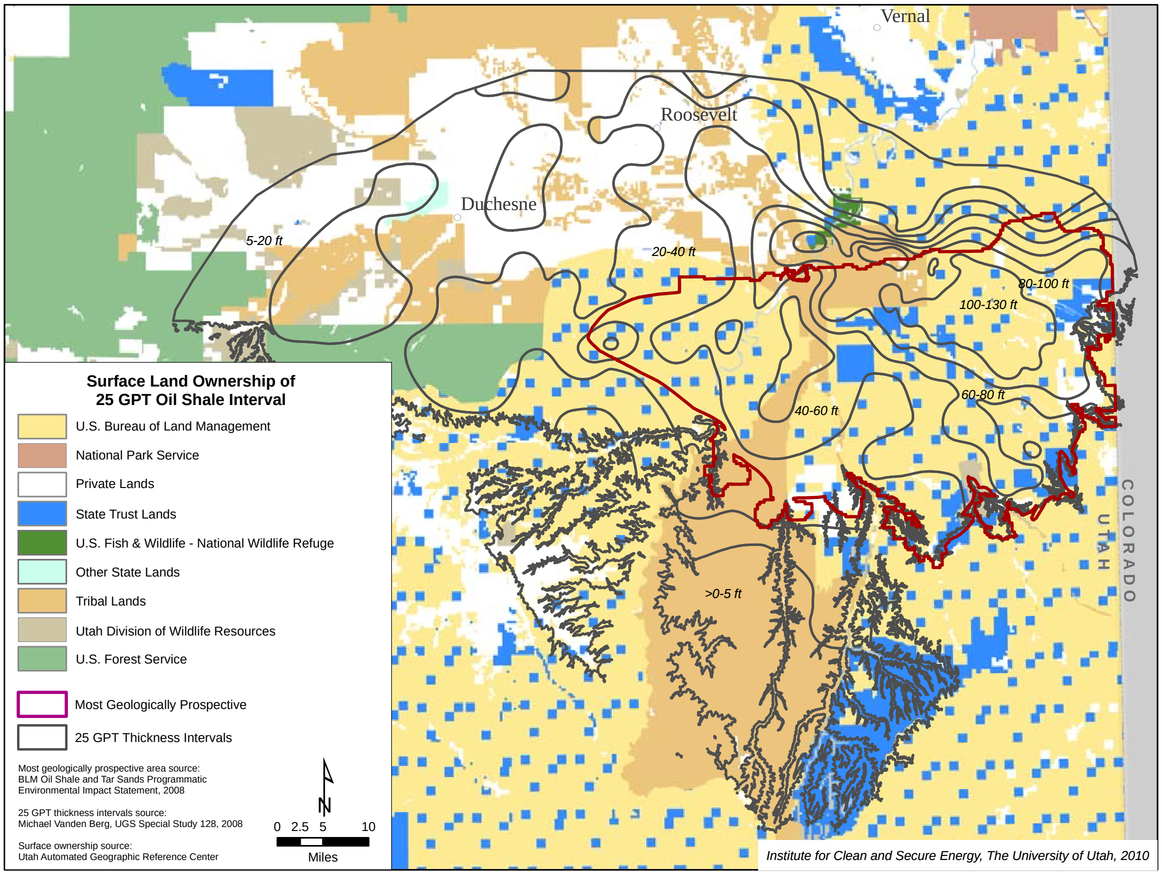

Figure 4.2: Surface land ownership in Utah's Uinta Basin, based on approved land transfers pending under the Utah Recreational Land Exchange Act.

Combined Hydrocarbon Leases that allow the lessee to withdraw both oil sands and conventional hydrocarbons. The validity of such existing leases is the subject of legal challenge. However, in general, most oil and gas development within Utah occurs in either the Uinta Basin or the southeast portion of the state; consequently the San Rafael, Tar Sands Triangle, Circle Cliffs and White Canyon STSAs are likely to experience far fewer colocated resource conflicts.

4.3.2 Land Use and the Endangered Species Act

As it does in the context of water, the ESA presents additional land use challenges for unconventional fuel development. The ESA generally prohibits the harming of "listed" animals, including significant habitat modification or degradation, and these protections apply regardless of land ownership. As of early 2011, Utah's Uintah County, situated in the Uinta Basin, was home to nine federally-listed or candidate species, eighteen species designated as state species of concern, and five species receiving special management under a Conservation Agreement in order to preclude the need for federal listing [37]. Sage grouse are one of these species. Roughly half the sage grouse habitat within Utah has already been lost due to habitat conversion, urbanization, energy and infrastructure development, and other factors [38]; populations have declined at a comparable rate [39,40]. Annual sage grouse status reviews will continue, and future listing may occur if the status of the sage grouse continues to decline.

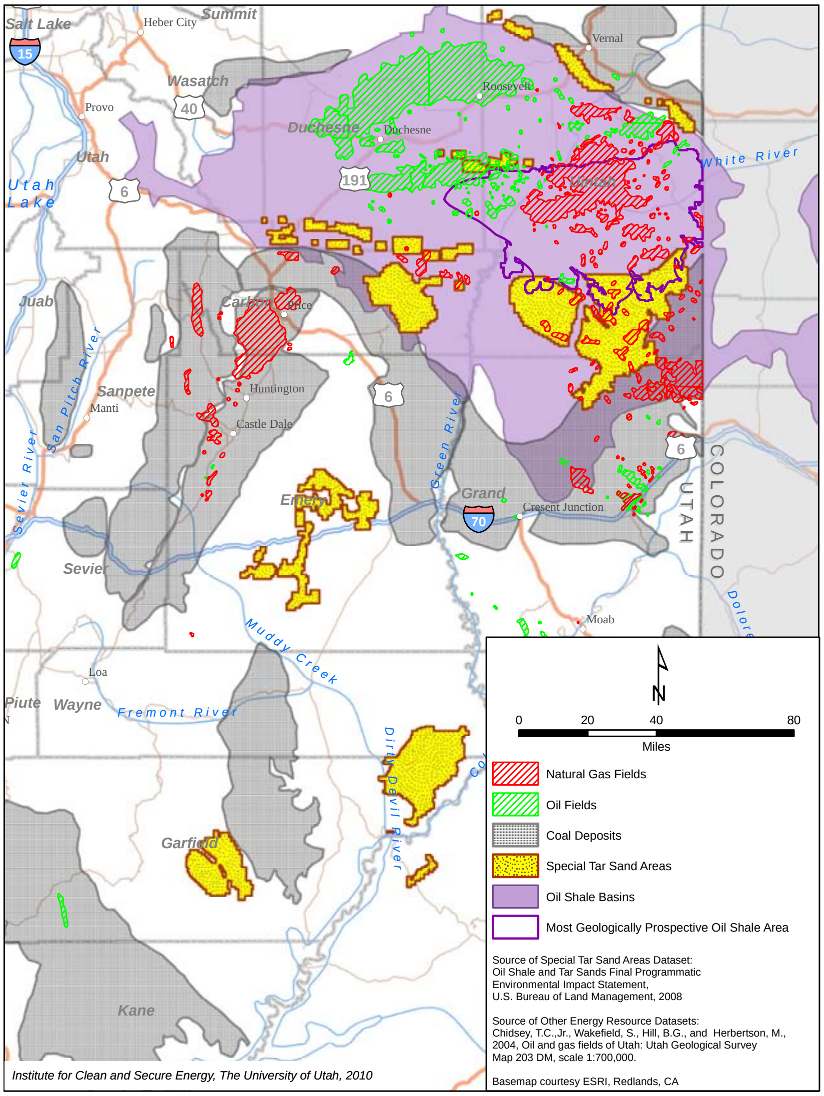

Figure 4.3: Uinta Basin resource colocation.

With respect to plant species, the most prospective oil shale area is home to several federally protected or ESA candidate plant species. While the ESA does not protect plants in the same manner that it protects animals, the Act does make it illegal to "remove and reduce to possession any such species from areas under Federal jurisdiction; maliciously damage or destroy any such species on any such area; or remove, cut, dig up, or damage or destroy any such species on any other area in knowing violation of any law or regulation of any State or in the course of any violation of a State criminal trespass law" [41]. Similar conflicts are inherent with oil sands development, although their broader distribution precludes a concise analysis here.

If commercial unconventional fuel development is to occur at more than nominal levels, energy companies and resource managers will need to reach across jurisdictional boundaries to solve complex, multifaceted problems. Collaborative approaches to project planning and management will likely be needed if unconventional fuel resources are to be developed in an efficient and environmentally sustainable manner.

4.4 Air Quality

Impacts to air quality-related values also pose a challenge to unconventional fuel developers. As the GAO recently acknowledged, "air quality . . . appears to be particularly susceptible to the cumulative affect of energy development, and according to some environmental experts, air quality impacts may be the limiting factor for the development of a large oil shale industry in the future" [16]. While the events giving rise to these concerns are associated with conventional oil and gas production, unconventional fuel development faces the challenge of an environment constrained by degraded ambient conditions.

4.4.1 Ozone Levels in Western, Energy-Producing Counties

In 2005, surprisingly high wintertime ozone levels measured in Sublette County, Wyoming, led to the placement of air quality monitors in rural, energy-producing counties in the western states of Utah, Colorado, Wyoming, and New Mexico. These monitors are reporting high wintertime ozone levels in areas previously assumed to be free of air quality problems. Within the Uinta Basin, "[m]onitored winter 2011 ozone levels reached a high 8-hour average value of 139 parts per billion (ppb) during inversion conditions—levels nearly twice as high as the federal health standard. The Utah Division of Air Quality (UDAQ) wintertime monitoring studies for 2007, 2008, and 2009 have shown that during inversions PM2.5 concentrations are at or above the standard and can be as high as those seen along the heavily populated Wasatch Front" [42]. However, winter 2012 ozone levels remained consistently below federal standards, likely because mild winter conditions were not conducive to ozone formation.

Why rural air pollution concentrations are elevated is unclear. Pollution transport from ever growing population centers, wildfires, oil and gas production, or some combination these factors may be involved. Whatever the cause, failure to meet federal air quality standards could necessitate increased regulatory controls and adversely impact economic development within the Uinta Basin. Ongoing monitoring and modeling efforts, as well as continued development of a basin-wide emissions inventory, will provide important information needed to develop air quality management strategies. Reductions in emissions of volatile organic compound and oxides of nitrogen have been tentatively identified as potential mitigation measures [43].

4.4.2 Monitoring Air Quality and Regulatory Oversight

Congress drafted the CAA to allow states a leading role in addressing air quality problems. However, because many western counties have a high percentage of Indian lands, oversight of air quality can be split among states, EPA, and Indian tribes. EPA has primary regulatory jurisdiction over Indian Country (see Figure 4.4), where 72% of oil and gas production occurs [44]. BLM oversees management and lease issuance for energy exploration, production, and transportation on federal and most Indian lands. Language in the Federal Land Policy and Management Act (FLPMA), has been interpreted to mean that BLM must "[r]equire compliance with air . . . quality standards established pursuant to applicable Federal or State law" before approving any type of land use, including mineral leases [45].

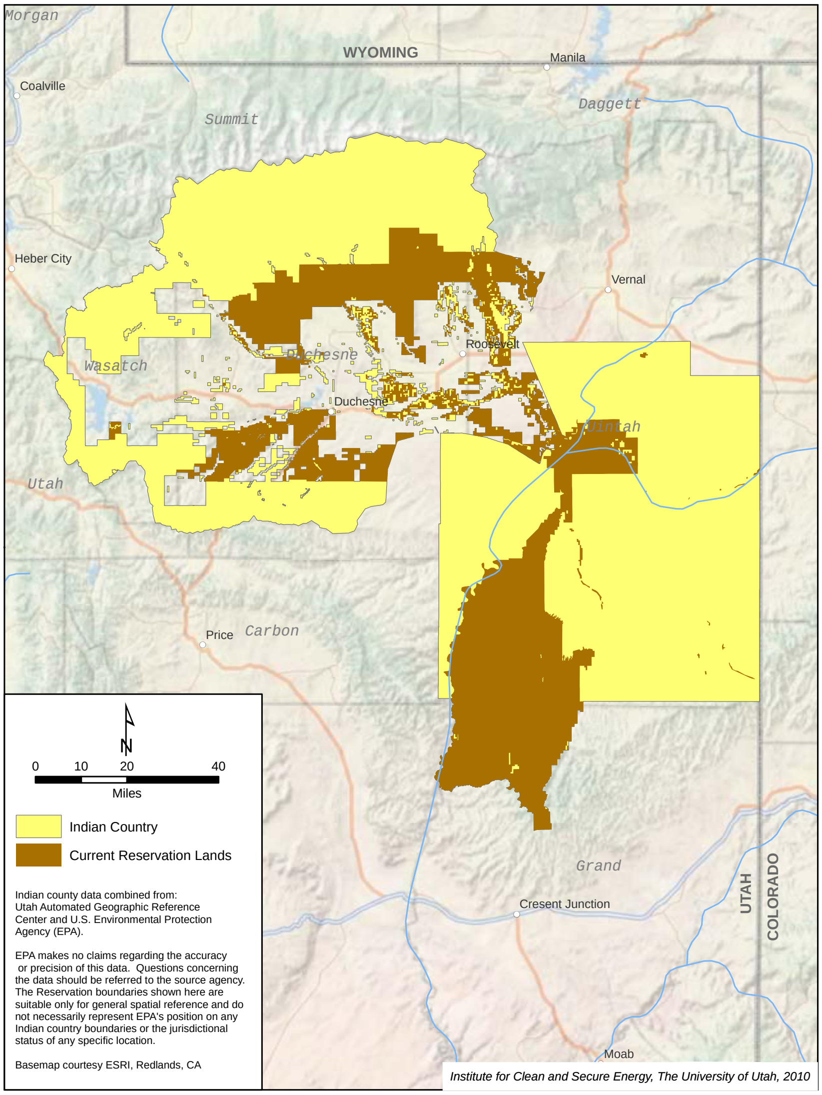

Figure 4.4: Indian Country.

Since BLM is mandated to comply with federal air quality standards, lawsuits have halted issuance of federal oil and gas leases, based at least in part on potential CAA violations [46]. Because the legal threshold for when BLM must refrain from issuing leases in order to avoid air quality violations is largely untested, BLM has voluntarily halted issuance of new leases and delayed completion of National Environmental Policy Act (NEPA) studies to allow it more time to develop methods to monitor and manage clean air issues on its lands [47].

Each state is required to develop a State Implementation Plan (SIP) that provides for implementation, maintenance, and enforcement of federal National Ambient Air Quality Standards [48]. SIPs require emissions reductions over time. However, provided federal standards are satisfied, SIPs permit states to exercise discretion as to the sources targeted and the severity of the restrictions. States also are allowed to consider economic and technological feasibility. States generally lack jurisdiction to implement the CAA within Indian country [49]. Therefore, in the Uinta Basin, which includes several million acres of Indian country, EPA will develop the implementation plan. Under such circumstances, local communities often worry that EPA lacks the local knowledge and flexibility needed to craft innovative response strategies that protect local economic interests. A related concern in the Uinta Basin is that BLM could slow or halt energy development activities, including those related to unconventional fuels, in an effort to effect compliance with federal standards.

EPA has primary regulatory jurisdiction over Indian Country, which includes the Uinta Basin as seen in Figure 4.4.

Monitoring air quality will be central to any effort to manage emissions within the Uinta Basin. If data indicate that the area is heading for non-attainment, local and state governments will be anxious to understand their options and to act.

4.5 Carbon Management Strategies

The issues and uncertainties associated with various carbon management strategies are ever-present in modern energy policy analyses. As discussed in Section 1, the absence of meaningful, specific emissions reduction targets and/or mechanisms for carbon pricing hinder both energy policy and energy resource development. This is particularly true for unconventional liquid transportation fuel resources, which typically require more energy to produce and consequently generate more GHG emissions than conventional transportation fuels.

4.5.1 Carbon Footprint of Conventional and Unconventional Fuels

The WTP cycle includes raw material extraction, transportation, processing (including upgrading), refining, and delivery to the pump. The WTW cycle extends the WTP cycle to include tailpipe emissions from fuel consumption.

When comparing unconventional and conventional fuel sources, it is important to consider the fuel's entire life cycle. Figure 4.5 shows GHG emissions from both well-to-pump (WTP) cycle and well-to-wheel (WTW) fuel cycles for a conventional source of crude oil.

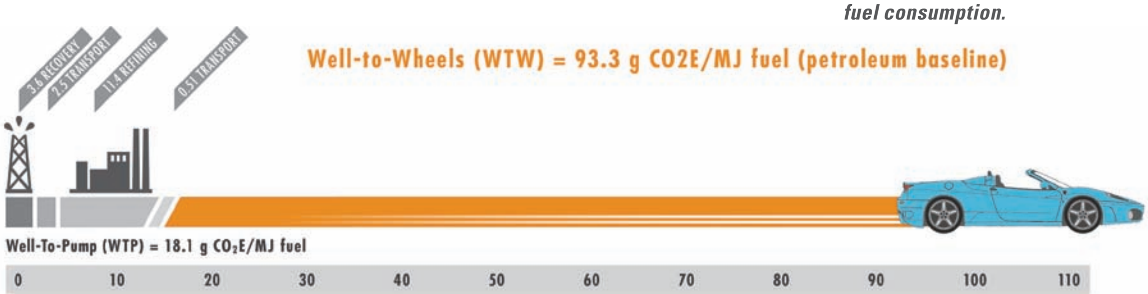

Figure 4.5: WTP and WTW GHG emissions for gasoline produced from conventional crude oil; data based on [50,51]. The GHG emissions in CO_2 equivalents (CO_2e) include emissions of CO_2, methane (CH_4), and nitrous oxide (N_2O).

Units in the figure are given in grams of CO_2 equivalent per megajoule of energy released (g CO_2e/MJ).

Worldwide, WTP GHG emissions for producing a barrel of crude oil are sure to increase. The EIA projects that world production of unconventional liquid fuels, which require more energy to produce and generate larger WTP GHG emissions, will increase from 3.4 million BPD in 2007 to 12.9 million BPD (accounting for 12% of world liquid fuel supply) by 2035 [52,53]. For example, Canadian oil sands, Venezuelan bitumen, and California heavy oil all have greater WTP GHG emissions than U.S. conventional crude oil; see Figure 4.6. However, high WTP GHG emissions are not limited to unconventional fuels; Nigerian crude has the fourth highest WTP GHG emissions profile in Figure 4.6, primarily due the venting and flaring of nearly all of the co-produced natural gas [52].

GHG emissions (CO_2e) include emissions of CO_2, CH_4, and N_2O. LHV refers to the lower heating value of the fuel.

PADD is the Petroleum Administration Defense District, and PADD2 is the Midwest district.

Uncertainty associated with Venezuelan crude production is high. Also, the emissions for the two oil shale processes are estimates only as there is no commercial U.S. production of fuel from oil shale.

For the oil sands labels, (1) denotes the narrow system boundaries and (2) denotes the wide system boundaries in a Cambridge Energy Research Associates (CERA) report [57].

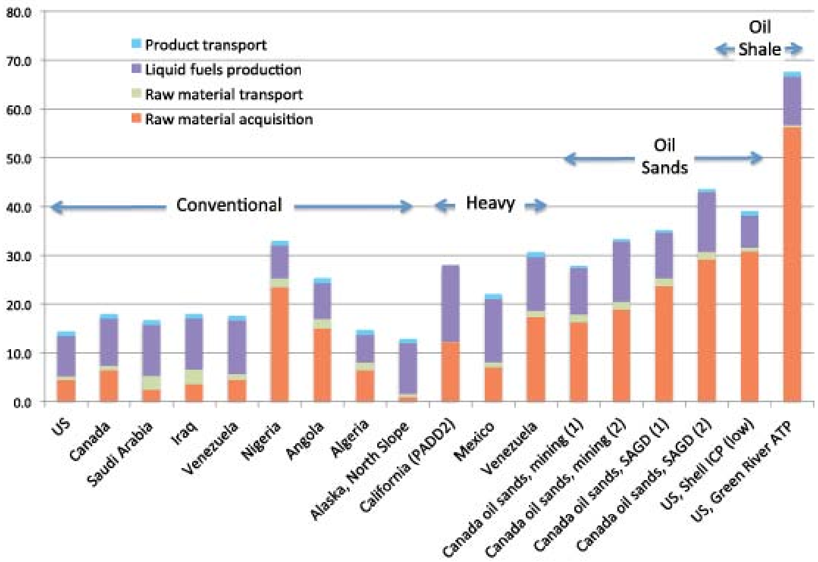

Figure 4.6: WTP GHG emission profiles for gasoline produced from various sources of crude oil. Data for this figure were obtained from [52,54–58].

As with conventional resources, a good deal of variability in WTP GHG emissions exists within unconventional resource types. Brandt et al. [55], CERA [57], and Charpentier et al. [58] have summarized several studies of WTP GHG emissions, Brandt et al. for oil shale and the other two references for oil sands. With oil sands, the range of variability results from the individual sands resource, the extraction and processing methods, system boundaries, allocation of co-products, and, to a lesser extent, the transportation requirements. Table 4.1 illustrates the range of WTP GHG emissions for conventional crude, oil sands produced from surface mining (Canada), oil sands produced from in situ methods (Canada), oil shale produced from surface mining and retorting, and oil shale produced from in situ methods. As oil shale is not yet produced commercially in the U.S., the range of reported WTP GHG emissions is wider than for oil sands or conventional oil.

Table 4-1. WTP GHG emissions from conventional and unconventional oil sources.

The high estimate for oil sands emissions is the upper estimate for processes that either gasify a portion of the bitumen or use coke as fuel for SAGD operations.

Crude Source	Low (g CO_2e/MJ)	High (g CO_2e/MJ)
Conventional	14[a]	33[b]
Oil sands - in situ	29[a]	55[c]
Oil sands - ex situ	27[d]	35[d]
Oil shale - Green River ATP	62[e]	75[e]
Oil shale - Shell in situ proces	38[f]	63[f]
Oil shale - various methods	46[g]	180[g]

References: (a) 50; (b) 52; (c) 59; (d) 60; (e) 55; (f) 54; (g) 61

4.5.2 Low-Carbon Fuel Standards

Because of the larger life-cycle carbon footprint of unconventional fuels, these fuel producers face challenges with the implementation of low-carbon fuel standards (LCFS). CARB approved the first LCFS on April 23, 2009; it became law on January 12, 2010 [62]. California's LCFS requires oil refineries and distributors to ensure that the mix of gasoline sold in California by 2020 does not exceed 89 g CO_2e/MJ; additional standards have been set for other transportation fuels. California's LCFS standard is a WTW life-cycle standard based on GHG emissions from extraction, processing, refining, distribution, and vehicle tailpipe emissions.

Biofuels and Canadian oil sands producers objected to California's LCFS, asserting that (1) the LCFS discriminated against their fuels, (2) too much uncertainty exists regarding the GHG impacts associated with land-use change and biofuels production, and (3) crudes already refined in the state, even if they have high WTP GHG emissions, are essentially grandfathered in [63]. On December 29, 2011, a federal judge issued a preliminary injunction against California's LCFS in part because it unconstitutionally discriminates against out-of-state fuel producers and regulates activities that occur entirely outside the state of California. CARB appealed the decision, and the injunction was lifted in April of 2012 while the appeal is being considered.

As part of California's LCFS, existing crude sources already refined in the state can use the baseline WTP GHG value, even if their WTP emissions are higher than the baseline or their production increases. New crude sources with WTP GHG emissions higher than 15 g CO_2e/MJ must develop emission intensity values, making them potentially less attractive.

Other U.S. states and regions have proposed LCFS, and eleven states have signed a letter of intent to create LCFS. However, to date no other LCFS have been passed.

At the federal level, the Energy Independence and Security Act of 2007, Section 526, prohibits any federal agency from entering into contract for procurement of an alternative or synthetic fuel produced from non-conventional petroleum sources unless the life-cycle GHG emissions associated with the "production and combustion of the fuel" are less than or equal to the equivalent petroleum fuel produced from conventional petroleum sources (93.3 g CO_2e/MJ petroleum baseline) [51,64]. This is a key benchmark against which all alternative fuels are currently measured for environmental acceptance.

4.5.3 Opportunities for Improving the Carbon Footprint of the Unconventional Fuel Cycle

Because the fuel-consumption life-cycle stage is responsible for the majority of WTW GHG emissions (see Figure 4.5), it generally presents the greatest opportunity for reducing the fuel-cycle's carbon footprint. This is particularly true for conventional sources of crude oil. For example, improving the average efficiency of a gasoline-powered passenger vehicle efficiency from 21.6 miles per gallon (MPG) to 28.6 MPG reduces the life-cycle WTW GHG emissions by 20%—equal to the average WTP GHG emissions in the U.S. [52].

For unconventional crude oil sources, the raw material extraction, processing, and upgrading life-cycle stages can be important contributors to the carbon footprint as seen in Figure 4.7. This figure includes fuel use (e.g. combustion) to illustrate how WTW GHG emissions from different sources of crude and processing methods would compare to a WTW LCFS such as California's.

Although upstream life-cycle stages are important contributors to the carbon footprint, substantial reductions in GHG emissions would be required for these life-cycle stages to produce a 20% reduction in WTW GHG emissions. For example, reducing GHG emissions from the in situ extraction and subsequent upgrading of Canadian oil sands by 75% would decrease WTW GHG emissions by 18% ("Oil Sands in situ" case from Figure 4.7).

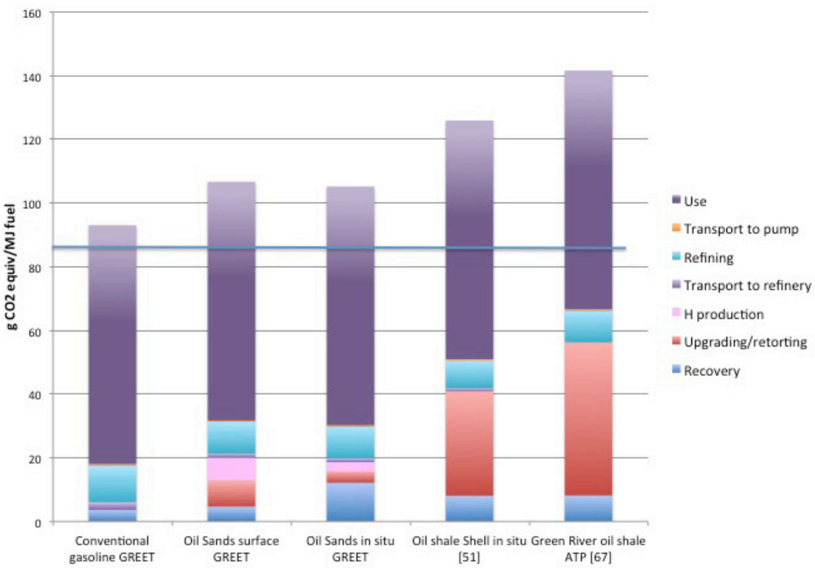

Figure 4.7: WTW GHG emissions for conventional fuel, oil sands, and oil shale. The blue line indicates California's LCFS in 2020.

4.5.3.1 Oil Shale Production

In laboratory- and pilot-scale tests of various oil shale production methods, the two main sources of GHG emissions are the production of thermal and electrical energy to power the operation and the decomposition of carbonate minerals that are present in certain types of oil shales. For thermal and electrical energy production, lower carbon sources that have been proposed include a high-efficiency, combined-cycle natural gas power plant [65] and renewable sources such as wind and solar [54,66]. As pointed out by Brandt [54], in situ thermal production methods would not likely be affected by the intermittency of renewables due to long heating times and the large thermal mass and high heat capacity of the oil shale. Carbon capture and sequestration (CCS) has also been examined as a way to mitigate power-generation emissions with recent studies looking at possible sequestration and enhanced oil recovery targets in saline formations in the Utah's Paradox Basin [67]. For ex situ production processes, the surface retort is a large stationary source of GHG emissions that might be amenable to CCS.

Other efficiency measures can reduce energy input requirements. With ex situ production, the hot, spent shale exiting the retort can be used to heat other process streams in the plant. For in situ production, efficiency can be improved by introducing fractures in the formation, thus allowing for convective and not just conductive heat transfer and a commensurate drop in heating time from years to months. Both Chevron and AMSO have proposed methodologies that allowing for convective heating of an in situ retort created by fracturing [68,69]. Brandt surmises that a conductive heating method such as Shell's ICP would reuse waste heat from depleted production cells, thereby increasing efficiency [54].

With respect to mineral decomposition, research has shown that carbonate minerals in oil shale begin decomposing (and releasing CO_2) near 1049°F (565°C) for dolomite and 1148°–1247°F (620°–675°C) for calcite [70,71]. Through understanding of the mineralogy of a particular oil shale resource and careful monitoring of process conditions/temperatures, the carbonate decomposition temperature window(s) can be avoided. However, the tradeoff for operating at lower temperatures is that residual carbon is left on the spent shale rather than burned, thus lowering the thermal efficiency of the process.

In both oil shale scenarios in this report (Sections 6 and 7), heat exchangers are used in the hydrotreater and the hydrogen plant (see Figures 6.8 and 6.9) to recover heat from process streams, thereby increasing overall plant efficiency. Additionally, in the ex situ oil shale scenario (Section 6), heat from the hot, spent shale is used to turn boiler feed water into steam.

4.5.3.2 Oil Sands Production

The Government of Alberta has a climate-change strategy focused on three areas: energy conservation, green-energy construction, and CCS [72]. The Canadian oil sands industry is beginning to fund studies of carbon capture from its upgrading and in situ processes. For example, the Alberta Energy Research Institute announced a C$650 million fund for large-scale demonstration of CCS that could result in storage of five million metric tons of CO_2 annually by 2015 using existing technology [73]. However, Jacobs [74] evaluated the cost and effectiveness of various efficiency improvements and carbon-capture technologies for in situ oil sands operations and concluded that improved efficiency was more cost-effective than CCS to reduce GHG.

A metric ton is equivalent to 1000 kilograms.

Additionally, the Canadian oil sands industry has been actively pursuing projects aimed at reducing their carbon footprint. Flint [60] summarized opportunities for reducing GHG emissions from the oil sands industry, including a significant opportunity with in situ SAGD operations by using solvents to replace or enhance steam injection (potential reductions of 25–75%). As surface mining of oil sands is a more mature industry, opportunities for GHG reduction are incremental, such as reducing diesel-fuel consumption by vehicles and improving heat recovery of the warm recycle water from the tailings. However, alternative surface extraction processes (paraffinic solvents, Shell Albion process), may realize increased efficiencies by improving on solvent recovery methods. Jacobs [75] evaluated potential efficiency improvements in a bitumen upgrading and refining process for six different technology scenarios. Due to system efficiencies, fuels produced from a combined upgrader/refinery had a lower GHG burden than fuels produced from an upgrading process followed by a refining process with a SCO intermediate.

As with the oil shale scenarios, the upgrading step for this report's oil sands scenarios includes heat exchangers in both the hydrotreater and the hydrogen plant; see Figures 6.8 and 6.9. These heat exchangers improve the energy efficiency of the process by using waste heat to generate steam and to preheat feed streams.

4.6 References

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5 Scenario-based Approach to Microeconomic Analysis of Unconventional Liquid Fuel

5 Microeconomic Analysis of Utah Unconventional Fuel Production Scenarios

The financial analysis of the scenarios in this report includes two components. The first component is an estimation of the various costs associated with the extraction, upgrading, and transportation to market of unconventional oil from Utah oil shale and oil sands, including capital costs, operating costs, taxes/royalties, and net earnings. The second component, project revenue, is estimated based primarily on projections of the price of oil and the oil production rate for each scenario. A number of measures of profitability are applied to the cost and revenue estimates, and the results are reported for each scenario. All costs, revenues, and profitability measures are reported in terms of real dollars (adjusted for inflation).

There are additional revenues from the sales of byproducts such as steam and sulfur (all scenarios), petroleum coke (oil sands scenarios), and CO_2 (scenarios with carbon capture).

In this report, the term "microeconomic analysis" is a synonym for "profitability analysis." The term is used to distinguish the attractiveness of these scenarios as private investments from the broad regional economic impacts that may result as side-effects if the scenario were realized. The term "macroeconomic analysis" or "economic impact analysis" denotes these latter effects which may result from, but do not cause, private investment.

5.1 Scope of Scenarios

The scope of each scenario is slightly different due to resource size/quality and the nature of the extraction process. All scenarios are assumed to start in 2012 and end in 2035, giving a total of 24 years for design, construction, startup, and production. While the present analysis ends in 2035, the actual productive lifespan of any equipment or facilities could be longer. Based on the relative size of each resource, oil shale and oil sands scenarios are sized to produce 50,000 BPD and 10,000 BPD, respectively.

EIA pricing forecasts for oil are only available until 2035.

For ex situ scenarios, design work is assumed to take one year to complete and commences in 2012; construction work is assumed to take three years. The buildup to the full production capacity of 330 days of operation per year (assuming approximately one month of downtime for annual maintenance) is assumed to take two years. These assumptions result in 20 years of operation for the ex situ oil shale and oil sands scenarios, including two years of startup and 18 years of full operation.

CERI assumed a three year construction period in their 2011 supply cost analysis of oil sands projects [1].

In situ oil retorting requires 27 years of heating prior to reaching peak production based on simulation results discussed in Section 7.1.1.1. The in situ oil shale scenario is designed to reach full processing capacity (90% of 50,000 BPD) in 2035, with the caveat that peak production will occur beyond the time scale of this analysis. Drilling and heating of in situ oil shale wells begins in 2013, with one-quarter of the total required number of wells drilled each year from 2013 to 2016. Thus, the maximum heating period for any well in this scenario is 23 years. Upgrading facilities are constructed according to the same schedule as the ex situ scenarios (see Section 5.2.1), but they do not operate at full capacity (330 days of operation per year) until 2035 and are instead run only as needed to handle the buildup in oil production. Oil produced before construction of upgrading facilities is complete is sold "as is" to refiners at a discount and is transported by truck from the wellhead to North Salt Lake City, Utah. The impact on profitability of operating the upgrader at

Production of raw shale oil in year 24 is 42,321 BPD, which, after upgrading, yields 46,810 BPD of upgraded shale oil (90% of 50,000 BPD). Peak production of 61,268 BPD of raw shale oil occurs in year 31 (2042).

full capacity beginning in year 7 (e.g. after startup) by running as a merchant upgrader is examined in this scenario's sensitivity study; see Section 7.3.4.

To operate as a merchant upgrader, raw shale oil would be purchased from local suppliers and gradually replaced with shale oil produced in situ.

The in situ oil sands scenario has a production rate at full capacity of 10,000 BPD and is based on Connacher's Great Divide 24,000 BPD SAGD expansion project [2]. In situ oil sands wells produce rapidly and are depleted within eight years, so wells in this scenario are drilled continuously throughout the project following a scaled version of the drilling schedule proposed by Connacher [2]. Of 96 well pairs (one injector/one producer) that must be drilled, 24 are drilled in last year of the project's construction phase (2015) with at least one well pair being drilled every year thereafter; see Tables 5-1 and 9-3 for the detailed drilling schedule. This scenario assumes that a production level of 10,000 BPD from the wells is reached at the end of the two-year start up period for the upgrading facilities.

The liquid fuel (e.g. raw shale oil or bitumen) extracted from each resource is upgraded to the quality of a light, low-sulfur benchmark crude oil such as WTI and transported via pipeline to a refinery where it is sold. By producing a light, low-sulfur crude, there are no quality-based price differentials to account for in the analyses. The scenarios include the following elements: production, primary and/or secondary upgrading, and transportation to a refinery. A carbon management element, included as a variation of all the scenarios, consists of an oxy-combustion system with CO_2 capture where the product is a nearly pure CO_2 stream compressed to pipeline conditions.

An overview of oxy-combustion and other CO_2 capture technologies can be found on the Vattenfall website [3].

Numerous technologies have been reported for production of liquid fuel from oil shale and oil sands. A recent report from DOE [4] highlights many of these technologies. Where possible, the scenarios in this assessment focus on extraction technologies that have shown feasibility at a pilot-scale or larger and for which some data are available. The costs for constructing and operating a plant using the selected extraction technology are included in the respective scenario analyses.

While light crude oils are easily refined into useful liquid fuels, lower API crude oils including oil sands bitumen and raw shale oil produce lower quantities of gasoline, diesel and jet fuel. Upgrading is the process of converting these lower value oils to higher API synthetic crude oils more suitable as conventional refinery feedstocks. A review of various upgrading methods can be found in a 2007 ICSE report [5]. Primary upgrading is mainly a molecular weight reduction process while secondary upgrading involves the removal of impurities from the crude oil and the addition of hydrogen to unsaturated bonds. Primary upgrading produces a lighter, less viscous oil while secondary upgrading produces a refinery-ready feed stock. The mainstays of primary upgrading of bitumen produced from Canadian oil sands have been delayed coking and flexicoking. These processes thermally crack the long chain hydrocarbon molecules in the bitumen into shorter chain molecules and a petroleum coke residue. A common secondary upgrading process is hydrotreating. Hydrotreating opens ring structures, shortens hydrocarbon molecule length, and removes heavy metals, sulfur as hydrogen sulfide (H_2S), and nitrogen as ammonia (NH_3). The large quantity of H_2 required for hydrotreating is typically supplied by steam methane reforming with natural gas as both a feedstock to and fuel for the process [6].

During hydrotreating, hydrogen (H_2) is reacted with crude oil at high pressure and temperature using a catalyst.

Approximately 2000 standard cubic feet (SCF) of H_2 (57 cubic meters) are required per barrel of raw shale oil.

In this report, the end objective of the upgrading process is to produce a crude with API gravity, sulfur and nitrogen content, and distillate cuts similar to those of WTI. The costs of upgrading, including the cost of a hydrogen production unit to supply the H_2, are included in the scenario analyses.

The upgrading plan for the various unconventional fuel scenarios, which depends on the quality of the bitumen or raw shale oil coming from the production process, is determined using the type of information shown in Figure 5.1. Raw shale oil from Utah's Green River Formation is light enough (right side of the High conversion box in Figure 5.1) that primary upgrading is unnecessary and it can be directly hydrotreated. Bitumen from Uinta Basin oil sands requires both molecular weight reduction (primary upgrading) and hydrotreating.

Yield results from both coking/hydrotreating and hydropyrolysis/hydrotreating bitumen upgrading sequences can be found in Oblad et al. [7].

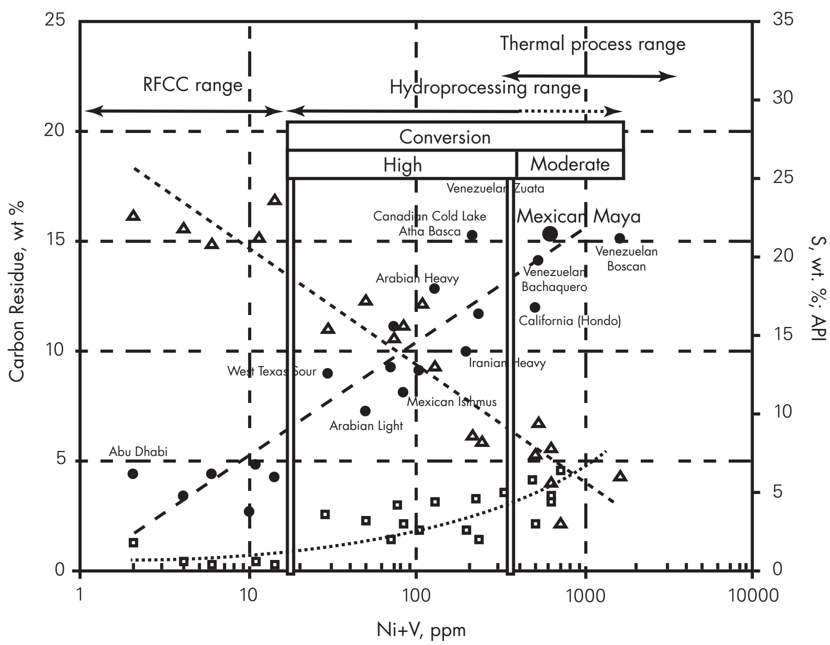

Figure 5.1: Heavy oil upgrading choices as a function of 343ºC (649ºF) residue properties; adapted from Rana et al. [8].

Crude oils are comprised of many different chemical species with a range of boiling points. A 343ºC (649ºF) residue refers to the liquid remaining after heating an oil to that temperature.

Further upgrading requirements for each scenario are based on oil properties, specifically the oil's distillate cuts, API gravity, and sulfur and nitrogen content. The variability in raw shale oil quality as a function of the production process is noted in Table 2 of Burnham [9], where API gravity ranges from 19°–45° and nitrogen content ranges from 0.5–2.1 wt%. Other oil properties such as heavy metal content are not investigated in this report.

Transportation of crude oil from the well head or surface processing facility to the upgrader takes place by a variety of methods including trucking and short pipelines. However, these transportation costs are not included in the scenario analyses.

The market for the scenarios in this report is the North Salt Lake City refineries. From the upgrader, transportation to the refineries takes place via pipeline. The cost of constructing and operating a new pipeline from the Uinta Basin to these refineries is included in the scenario cost. The pipeline is assumed to follow the same route as existing pipelines operated by Chevron Pipe Line Company.

Utah refineries have the capacity to process 176,400 BPD. However, there is currently no idle capacity in Utah or anywhere else in the PADD IV region (Colorado, Montana, Utah and Wyoming) [10]. As a result, any production from the basin would displace other crude oil feeds in Salt Lake City. Nationwide there is approximately 843,000 BPD of idle capacity, so it is assumed that any displaced feeds would be processed elsewhere.

5.2 Profitability Measures and Annual Cash Flow

As oil is by far the leading source of revenue for an unconventional oil project, the price of oil over the lifetime of the project is a crucial factor in determining its commercial success. The question that must be answered is what range of future oil prices is sufficient to support unconventional oil projects?

Two methods of assessing profitability are employed to address this question for the unconventional oil projects described in subsequent sections of this report. The first method, referred to as the Supply Price Method, finds the minimum price of oil that would ensure profitability of the project if that price, adjusted for inflation, were to be received on each barrel of oil sold from the project. The second method, referred to as the Net Present Value (NPV) Method, evaluates the profitability of the project when the oil prices received are those of the most recent EIA oil price forecasts. Both the Supply Price Method and the NPV Method are based on a discounted cash flow framework.

5.2.1 Discounted Cash Flows

Discounted cash flows are used as the basic methodology to evaluate the profitability (i.e. economic feasibility) of production process scenarios in this study. This approach is primarily based on the economic analysis method described by Seider et al. [11] in which the cash flow is defined as the sum of all costs and revenue in a given amount of time. For this study, cash flows are calculated annually. On this basis, the cash flow for any given year n can be calculated using Equation (5.1).

$$CF_n = P_n(S - C_V) - C_F - T - R - C_{WC} - C_{TDC} - C_L - C_S - C_{RIP} - C_P - C_{drill} - C_{rec} \qquad (5.1)$$

In this equation,

More detailed descriptions of the terms in this equation can be found in Table 5-3.

Equation (5.1) is generalized so that it covers any year of the project. However, no year includes all of the terms listed and some terms are paid for over several years. See Table 5-1 for details on the timeline for capital cost investments.

For a definition of working capital, see Table 5-3.

CF_n = Annual cash flow in year n
P_n = Production capacity (days operated per year) for year n
S = Total gross sales per year at full production capacity
C_V = Variable operating costs per year at full production capacity
C_F = Fixed operating costs per year (applied during years of startup and production)
T = Taxes for year n (applied during years of startup and production)
R = Royalties on oil production in year n (applied during years of startup and production)
C_{WC} = Working capital
C_{TDC} = Total depreciable capital
C_L = Capital cost of mineral leases and of land on which production facilities are built
C_S = Capital cost of startup
C_{RIP} = Capital cost of royalties for intellectual property

C_p = Capital cost of permitting
C_{drill} = Capital cost of drilling (in situ oil shale scenario) or annual cost of drilling (in situ oil sands scenario)
C_{rec} = Cost of well reclamation (in situ oil shale and oil sands scenarios)

For the scenarios evaluated in this report, the scheduled activity and spending plan for each year is shown in Table 5-1 below. Using this table, the capital costs in Equation (5.1) that are applied each year of the project can be determined. For example, 25% of C_{TDC} is spent in year 2015, but C_{TDC} is 0 when calculating the cash flow for 2016.

Table 5-1. Project timeline for all scenarios.

Chronology				Investment							
Action	Year	P		C_{TDC}	C_{WC}	C_L	C_{rIP}	C_P	C_S	C_{drill}	
Design	2012	0%	0%	25%				100%			
Construction	2013	0%	0%	25%		100%				25%	
Construction	2014	0%	1%	25%						25%	
Construction	2015	0%	1%	25%						25%	24%
Startup	2016	45%	2%		-100%		100%		100%	25%	1%
Startup	2017	68%	4%								3%
Production	2018	90%	7%								7%
Production	2019	90%	9%								1%
Production	2020	90%	11%								4%
Production	2021	90%	13%								7%
Production	2022	90%	15%								16%
Production	2023	90%	19%								2%
Production	2024	90%	23%								11%
Production	2025	90%	27%								5%
Production	2026	90%	31%								4%
Production	2027	90%	36%								1%
Production	2028	90%	40%								9%
Production	2029	90%	45%								2%
Production	2030	90%	50%								1%
Production	2031	90%	56%								
Production	2032	90%	63%								
Production	2033	90%	71%								
Production	2034	90%	80%								
Production	2035	90%	90%		100%					Reclaim	Reclaim

Scenario Key:	
	All Scenarios
	In Situ Oil Shale
	In Situ Oil Sand

All scenarios begin in 2012 and end in 2035. Process design (assumed to account for 25% of C_{TDC}) and permitting (C_p) are completed in year one (2012). Construction of mining (for ex situ scenarios) and upgrading facilities (all scenarios) is assumed to take three years (total of 75% of C_{TDC} spread equally over the construction phase) and begins in year two (2013). The purchasing of mineral leases and of land for production facilities is also completed in year two to coincide with the beginning of construction. Once construction is complete, the remainder of the capital costs are invested (C_{WC}, C_{RIP}, and C_S) and production (P) is ramped up to full capacity (330 days of operation per year, or approximately 90% of the year) over the course of two years. In year five (2016), production capacity is at 45% while in year six (2017), production capacity is at 68%. Finally, at the end of the project in 2035, C_{WC} is recovered.

In addition, in situ scenarios require capital expenditures for drilling. In situ oil shale wells are drilled in the first four years after the design process is completed. In situ oil sands wells produce and are depleted within an eight-year time frame, requiring that drilling be spread out over the life of the project. The drilling schedule shown in Table 5-1 is based on Connacher's Great Divide 24,000 BPD SAGD expansion plan [2].

To account for the time value of money, the cash flow for each year of the project is multiplied by a discount factor *f*, defined as:

$$f_n = \frac{1}{(1+r_d)^n} \qquad (5.2)$$

where r_d is the desired annual discount rate that the entity financing the project wishes to make and *n* is the year of the project. Summing the discounted cash flows for each year of a project gives the NPV of the project:

The discount rate, r_d, is the rate used to render benefits and costs commensurate that occur in different time periods [12].

$$NPV = \sum_{n=1}^{k} f_n CF_n \qquad (5.3)$$

When Equation (5.3) equals zero (i.e. the NPV of a project is zero), the discount rate is defined as the IRR. The IRR is a particularly useful measure of profitability because it accounts for the time value of money and it allows for easy comparison of the financial merit of different projects.

Consider two projects, one that costs $2 billion and makes $3 billion over ten years, and the other that costs $10 million and makes $50 million over 5 years. The project with the higher calculated IRR is the better investment.

5.2.2 Supply Price Method

The supply price is the minimum constant dollar price an operator would need to receive per barrel of oil to ensure a profitable project. It includes all usual costs (capital expenditures, operating costs, royalties, taxes, etc.) plus a necessarily and sufficiently attractive return on investment (normal profit); costs and net earnings are positive contributors to the supply price. The supply price also includes all non-oil revenue streams (see Section 5.3) as negative contributors. It is the break-even price for oil at the specified hurdle rate, meaning that the rate of return (ROR) is included in the supply price. Because the ROR depends on the actual path of prices and costs, the ROR may be more or less than the hurdle rate.

To determine the supply price, a hurdle rate is specified and the corresponding discount factor is calculated from Equation (5.2). The real fixed price that results in NPV = 0 (Equation (5.3)) for cash flows (Equation (5.1)) discounted by the hurdle rate is the supply price. At the given hurdle rate, any oil price higher than the supply price results in NPV > 0 and any oil price less than the supply price results in NPV < 0. The supply price for a hurdle rate of 0% represents the break-even oil price if financing costs for the project are zero.

The hurdle rate is the minimum ROR, equivalent to r_d in Equation (5.2), that an investor requires before investing his/her funds in the project; it is a particular value of r_d. The hurdle rate represents the ROR on investments with similar risk/reward profiles (tradeoffs). That is, it is the opportunity cost of capital—the ROR one gives up on alternative investments by choosing to invest funds in this one [12].

5.2.3 Net Present Value Method

In the NPV Method, an oil price forecast and a hurdle rate are specified. Given the price of oil each year obtained from the forecast, cash flows are calculated using Equation (5.1) and the NPV is computed from Equation (5.3). For the specified oil price forecast and hurdle rate, a negative NPV indicates that the operation is not profitable while a positive NPV indicates a profitable operation. In other words, an NPV > 0 means the operation will return "super-normal" profits or profits greater than the hurdle rate.

The selling price for oil is discussed in further detail in Section 5.3.

The NPV method accounts for the time value of oil sales, but it is limited by the accuracy of oil price forecasts.

Alternatively, the NPV method can be used to compute the IRR for a specified oil price forecast. The IRR is computed by varying the discount rate r_d in Equation (5.2) such that the NPV in Equation (5.3) equals zero.

5.3 Selling Price of Synthetic Crude and Other Revenue Streams

The price of crude oil at the refinery fence depends primarily on political events and market conditions; to a lesser extent, it depends on oil properties. Annually averaged sale prices for various crudes are shown in Table 5-2. Note how the variation in price for each crude stream across time is much larger than the variation across streams at a given point in time. Nevertheless, at a given point in time, the highest prices are obtained for light crude oils with low sulfur, nitrogen, oxygen and heavy metal contents. Lower prices are obtained for heavy crudes as they require more expensive processing in the refinery.

Table 5-2. Domestic crude oil first purchase prices in dollars per barrel for selected crude streams; from EIA [13].

Crude Stream	2005	2006	2007	2008	2009	2010
Alaska North Slope	47.05	56.86	63.69	90.10	54.41	72.33
California Kern River	44.67	55.05	62.14	87.27	53.94	72.80
California Midway-Sunset	45.93	54.59	61.62	86.92	53.00	72.26
Heavy Louisiana Sweet	51.61	63.41	70.00	103.96	58.61	78.17
Louisiana Light Sweet	51.95	64.04	72.93	104.51	61.26	79.26
Mars Blend	46.13	57.35	63.37	93.40	57.21	75.44
West Texas Intermediate	53.90	63.16	69.59	97.39	57.27	76.63
West Texas Sour	50.72	59.03	65.56	95.31	56.63	75.03
Wyoming Sweet	53.94	60.52	64.79	89.30	51.68	70.43

This price differential for light versus heavy oils is illustrated in Figure 5.2. Plotted in this figure are the time series of light/medium crude oil prices and the discount applying to heavy oil and bitumen; all prices have been adjusted for inflation. These differentials illustrate the nature of the tradeoff for producers of heavy or otherwise low quality crude—that of the cost of investment in upgrading capability versus the premium on upgraded crude. The larger (smaller) the light-heavy differential, for example, the greater (lesser) the returns on an investment in upgrading capability.

The light-heavy differential itself will vary according to supply and demand conditions for the different grades of crudes.

In the scenarios analyzed for this report, the final product from the upgrading phase is similar to a light, low-sulfur crude (West Texas Intermediate in Table 5-2). It is assumed that the market value for such a crude is equal to the national average market value for a light, low-sulfur crude. Thus, a discount is not applied to the product prices for any of the scenarios.

Because of the importance of future oil prices on the profitability of unconventional oil projects, this report considers two options for oil pricing:

1. Fixed oil prices,
2. Three sets of oil-price forecasts provided by EIA [15].

The 2012 EIA energy forecasts [15] are for oil, natural gas, electricity and coal. These forecasts are performed annually by the U.S. DOE for three situations: high oil prices, low oil prices, and a reference forecast for normal

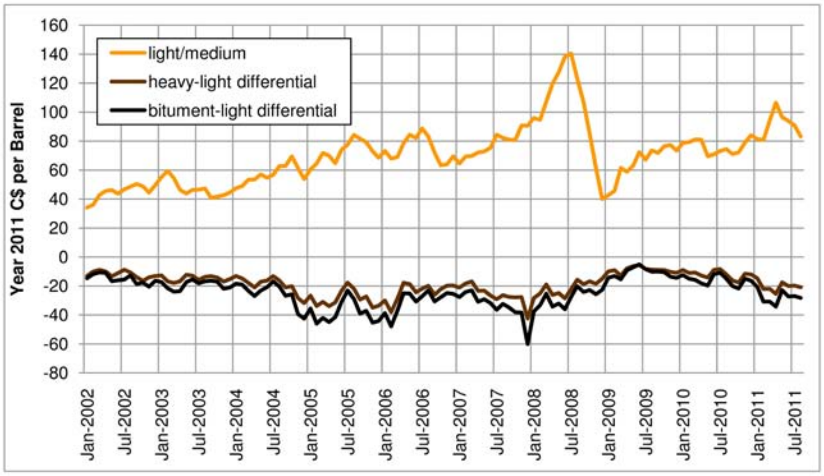

Figure 5.2: Light/medium crude oil prices in 2011 C$ during the period from 2002 to 2011 with corresponding discount applying to heavy oil and bitumen; data from the Energy Resources Conservation Board [14].

oil prices. Any one of these economic situations can be chosen to predict oil sales revenue and utility costs for natural gas and/or electricity using the computational tools developed for the scenarios in this report. The average and range of oil prices for each of the three 2012 WTI oil price forecasts are listed in Table 5-3. Plots of the 2010–2012 WTI oil price forecasts to 2035 are shown in Figure 5.3. As evident from the year-to-year forecast variability seen in Figure 5.3 and the variability in averages seen in Table 5-3, using these types of forecasts introduces large uncertainties into calculations of profitability for any type of oil development project.

Each EIA Annual Energy Outlook (AEO) report presents prices in real US$ two years prior to the report date (i.e. the AEO 2012 reports prices in 2010 US$). EIA forecasts used in this report have been adjusted to 2012 US$ using an inflation rate of 1.8%.

Table 5-3. Average and range of oil prices for each EIA oil price forecast for WTI (in 2012 US$).

Oil Price Forecast	Average Price ($/bbl)	2012 Price ($/bbl)	2035 Price ($/bbl)
Low	$63.87	$73.01	$64.65
Reference	$131.85	$98.17	$150.24
High	$192.45	$144.28	$207.64

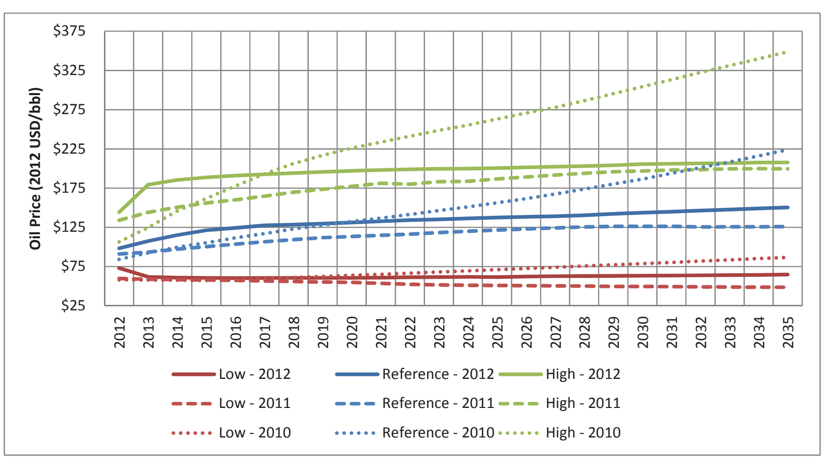

Figure 5.3: EIA 2010–2012 price forecasts for WTI crude under low, reference, and high oil prices [15-17]. Values are given in 2012 US$.

In addition to the sales revenue generated by oil, other products generated during upgrading, including petroleum coke, sulfur, and steam, are sold as byproducts. Each scenario also has the option of implementing CO_2 capture with the subsequent sale of CO_2 for enhanced oil recovery (EOR). When these byproducts are produced, it is assumed that they are sold free on board (f.o.b.) at the prices listed in Table 5-4 and are included in that year's sales revenue. Steam is sold back to the off-site utility contracted to provide steam to the plant. The selling price is half the cost of high pressure steam suggested by Seider et al. [11]. Sulfur prices are obtained from USGS mineral commodity summaries [18]. Petroleum coke prices are obtained from the EIA [19] but include delivery as no f.o.b. prices were available.

Free on board (f.o.b) is defined as the purchase price for any product without including costs for delivery.

Table 5-4. Sale prices (f.o.b.) of byproducts in 2012 US$ [11,18–20].

psig = pounds per square inch gauge
klb = thousand pounds
MMBtu = million British thermal units

Product	f.o.b. price ($)	per
CO_2	$25	ton
Steam (600 psig, 700°F)	$3.48	klb
Petroleum Coke (delivered)	$1.70	MMBtu
Sulfur	$100	metric ton

5.4 Supply Cost Methods

The various components of supply costs (capital and operating costs, taxes, and royalties) are computed for all scenarios in this report. An estimation of capital and operating costs for each year over the life of the project is made using industrial standard methods. Taxes and royalties are determined based on the landowner for the scenario and the applicable federal and state laws. Also included in the cost analyses are the depreciation and depletion for these operations. Depletion is similar to depreciation but applies to the removal of natural resources. As shale oil or bitumen are extracted, the value of the land owned/leased is reduced.

"Supply cost" refers to all costs for producing refinery-ready SCO, including capital and operating costs, taxes, royalties, and net earnings, put in terms of cost per barrel.

Depletion is a deduction that reduces corporate income taxes. This report uses cost depletion. See Section 3.4.2.2 for a discussion on depletion.

5.4.1 Capital Costing Methods

Capital costs are one-time expenses that are paid for land acquisition, drilling, equipment, construction, etc. The various capital costs included in this analysis are given below in Table 5-5. The combination of Williams' six-tenths rule [21] and the method of Guthrie [22] provide reasonable estimates of the total bare module investment (C_{TBM}) of each scenario (discussed in Section 5.4.1.1). Other capital costs, such as the cost of site preparation, mineral leases, and startup, are estimated as percentages of C_{TBM} as recommended by Seider et al. [11] and are listed in Table 5-5.

Table 5-5. Components of total capital investment, C_{TCI}; modified from Seider et al. [11].

As suggested by Seider et al. [11], C_{site} ranges from 4–20% of C_{TBM} and C_{serv} ranges from 5–20% of C_{TBM} depending on the amount of preexisting infrastructure.

Category	Symbol and Definition
Total Bare Module Investment (TBM)	C_{TBM} = Sum of costs for extraction and processing equipment
Cost of site preparation	C_{site} = 10% of C_{TBM}
Cost of service facilities	C_{serv} = 10% of C_{TBM}
Cost for pipelines (water and oil)	C_{pipe} = (Capital cost in $ / foot of length / inch diameter) x (length of pipeline) x (economic diameter calculated from [23]) + (construction cost from [24])
Cost for water reservoir	C_{resv} = RSMeans [25] cost data for excavating reservoir large enough to store enough water for 90 days of process operations
Allocated costs for utility plants	C_{alloc} = Sum of costs listed below: • Steam - $50 / lb/hr • Water - $58 / gpm • Refrigeration - $1,330 / ton • Electricity • Substation $203 / kW • Line - $425,000 / mile • Switching gear & tap - $10,000 / mile • Natural Gas • Line - $1,056,000 / mile • Metering & regulation facility - $1,000,000 (flat cost)
Total Direct Permanent Investment (DPI)	$C_{DPI} = C_{TBM} + C_{site} + C_{serv} + C_{pipe} + C_{resv} + C_{alloc}$
Cost for contingencies & contractor fees	C_{cont} = 15% of C_{DPI}
Total Depreciable Capital (TDC)	$C_{TDC} = C_{DPI} + C_{cont}$
Cost of leases/land	C_L = 2% of C_{TDC}
Cost of permitting	C_P = $0.10 / bbl of oil produced
Cost of royalties for intellectual property	C_{RIP} = 2% of C_{TDC}
Cost of plant startup	C_S = 10% of C_{TDC}
Investment site factor	F_{ISF} = 1.15 (for U.S. Midwest region)
Total Permanent Investment(TPI)	$C_{TPI} = F_{ISF}(C_{TDC} + C_L + C_P + C_{RIP} + C_S) + C_{drill} + C_{rec}$
Working Capital (WC)	C_{WC} = Sum of cash value of: • Cash Reserve - 30 days of manufacturing costs • Inventory - 7 days of sales • Accounts Receivable - 30 days of sales • Accounts Payable - 30 days of feedstock costs
Total Capital Investment (TCI)	$C_{TCI} = C_{TPI} + C_{WC}$

lb/hr= pounds per hour
kW = kilowatt
gpm = gallons per minute

For the U.S. Gulf Coast region, F_{ISF} = 1.00.

The C_{TCI} is used to determine the capital cost per flowing barrel (CPFB) for each project based on Equation (5.4).

$$CPFB = \frac{C_{TCI}}{Designed\ oil\ production\ capacity(BPD)} \tag{5.4}$$

However, the entire C_{TCI} is not invested as a blanket sum. Instead, itemized components of the C_{TCI} are invested over the years that comprise the design, construction, and startup of the project as described in Section 5.2. It is calculated only for use in profitability calculations like CPFB; it plays no role in the cash flow equation (Equation (5.1)).

Capital costs for the project are estimated using a combination of two techniques, namely Williams' six-tenths rule for economy of scale [21] and the individual factors method of Guthrie [22]. According to Williams [21], economies of scale in chemical processes (for everything from individual pieces of equipment to entire plants) can be described by Equation (5.5),

$$C = C_o \left(\frac{Q}{Q_o} \right)^m \left(\frac{I}{I_o} \right) \tag{5.5}$$

where C is cost, Q is material capacity (oil production rate, raw shale processed, etc.), m is a scaling power, I is an appropriate cost index, and the subscript o refers to the base value of the subscripted variable. Equation (5.5) is referred to as the "six-tenths rule" because Williams [21] found that, on average, the best fit to cost data was given by $m = 0.6$. As with a similar study by Weiss et al. [26], this study assumes that $m = 0.6$ for all capital costs. In some instances, Equation (5.5) is also used for estimating annual costs, in which case $m = 1$ (see the discussion of operating costs below). Cost indices used in this report are summarized in Table 5-6.

Table 5-6. Cost indices, their values, and uses.

Cost Index	Value	Date	Notes
CEPCI	577.4	09/2012	Chemical Engineering Plant Cost Index, used for all processing equipment designed and costed following guidelines published in Seider et al. [11].
ENR			Engineering News-Record
CCI	9412.25	12/2012	Construction Cost Index, used for pipeline construction
MCI	2888.62	12/2012	Material Cost Index, used for pipeline materials
HCI	185.7	01/2012	RS Means Historical Cost Index, used for reservoir construction
NFRCI	2448	07/2012	Nelson-Farrar Refinery Construction Index, used for H_2 plant, delayed coker, fractionator, amine treatment unit, sulfur recovery unit, sour water stripper
PPI			Producer's Price Index
Chemicals	260.8	11/2012	Used for retort chemicals (index ID: PCU 325)
Drilling	396.7	11/2012	Used for drilling (index ID: PCU 213111213111)
Mining	231.6	11/2012	Used for ex situ oil shale mine capital and operating costs (index ID: PCU 212)

The method of Guthrie [22, 27] requires an optimal process design with mass and energy balances, equipment sizing, selection of materials of construction, and a process control configuration. It accounts for the total direct and indirect (delivery, insurance, taxes, installation, etc.) costs of process equipment. The Guthrie method is applied by estimating the f.o.b purchase cost of each piece of equipment (C_p) and multiplying that cost by a series of factors to derive an installed or bare module cost (C_{BM}) as given by Equation (5.6):

$$C_{BM} = C_P\left(\frac{I}{I_o}\right)[F_{BM} + (F_d F_p F_m - 1)] \tag{5.6}$$

In this equation,

C_{BM} = bare module cost of equipment
C_p = f.o.b. purchase cost of equipment
F_{BM} = bare-module factor
F_p = pressure factor
F_d = equipment design factor
F_m = material factor

The factors in Equation (5.6) vary for each type of equipment. For example, the materials of construction can be different for a reactor or separation unit. The actual values used in this report are given in Seider et al. [11].

Additional data and algorithms are used to estimate capital costs for reservoirs, transportation pipelines, well drilling, and mining. RSMeans heavy construction cost data [25] is used to estimate the cost of building a reservoir for process water. The costs for transporting water and oil by pipeline are calculated by combining the economic pipeline diameter calculation of Peter and Timmerhaus [23] with the pipeline construction cost estimation methodology of Boyle [24]. Well drilling costs are estimated from several sources of data, including an industry consultant in the Uinta Basin [28] and costs from a database of oil and gas wells maintained by DOGM [29]. Mining costs (surface and underground) are estimated from mining cost models published by InfoMine [30].

5.4.2 Operating Costs

The operating costs in each scenario can be differentiated into variable (C_V) and fixed (C_F) costs based on whether or not they are functions of the operation of the process. In this report, variable costs are defined as a combination of utilities (water, fuel, electricity, etc.) and other expenses related indirectly to production, e.g. research and royalties for intellectual property. The fixed costs include the cost of labor, maintenance, property taxes and insurance, all of which are estimated as suggested by Seider et al. [11].

For the variable cost category, utility requirements are either taken directly from the scenario-specific process design flow sheet or scaled from base scenario process data using a variant of Equation (5.5) given below:

$$U = U_o\left(\frac{Q}{Q_o}\right)^m \tag{5.7}$$

where U is the utility requirement, the scaling exponent m is always set to 1, and all other variables are the same as in Equation (5.5).

Utility costs are estimated from price data given by Seider et al. [11], EIA [15], and others. Utility prices are calculated for each year of the project scenario. If EIA price forecasts for oil are used to estimate oil sales (e.g. the NPV Method), EIA forecasts for natural gas and electricity are also used [15]. Otherwise, utility prices are fixed at the values given in Table 5-7 from the sources cited. Utility pricing volatility, though not explicitly accounted for in the analyses that follow, will have an impact on any profitability measures. Natural gas price volatility is addressed in the sensitivity analysis for each scenario.

For example, the price of natural gas has dropped significantly since the 2011 EIA price forecast as noted in Table 5-7.

Table 5-7. Utility pricing for unconventional fuel scenarios in 2012 US$.

Utility	Price	Per	Notes
Catalyst[a]	$4.24	kilogram	Based on price quote received for CoMo NiMo hydrotreating catalyst
CO_2[b]			
Sale Rate	$25.00	ton	
Tax Rate	$25.00	ton	
Electricity[c]	$0.059	kWh	kWh = kilowatt - hour
Fuel			
Purchase Price[c]	$6.16	MMBtu	Average price from EIA Reference forecast to 2035 is $6.32; average price for third quarter of 2012 is $2.81.
Transmission Fee[d]	$0.18	MMBtu	
Reimbursement Fee[d]	1.37%	of annual purchase cost	
Oxygen[e]	$70.00	ton	Price range for low pressure, cryogenic O_2 with 95–99% purity is $60–$90/ton
Refrigerant (R-134a)[f]	$7.90	GJ	GJ = gigajoule
Retort chemicals[g]	$0.14	bbl of oil produced	Value from reference has been scaled by the PPI
Solvent[h]	$8.98	gallon	
Steam[f]			
Low pressure (50 psig)	$3.00	klb	
High pressure (450 psig)	$6.60	klb	
Water			
Purchase[i]	$50	acre-feet / year	
Treatment			
Cooling[f]	$0.08	kgal	kgal = thousand gallons
Boiler Feed[f]	$1.80	kgal	

References: (a) 31; (b) 20; (c) 15, 32; (d) 33; (e) 34 ; (f) 11; (g) 26; (h) 35; (i) 36

In addition to the utility costs given above, costs for conducting research of \$0.74 per barrel (/bbl) of oil produced are also included as a variable expense based on estimates of research spending in Alberta, Canada [37]. An annual fee covering royalties for intellectual properties, R_{IP}, is also included. R_{IP} is assumed to be 3% of the cost of manufacture (*COM*), defined by Seider et al. [11] as:

$$COM = C_V + C_F + D \tag{5.8}$$

where C_V and C_F are the sum of all variable and fixed operating costs and D is depreciation. The value of C_V used in Equation (5.8) is the sum of all variable costs excluding R_{IP}, since R_{IP} is itself a variable cost.

For the fixed expenses category, labor is included because the large amount of manpower required during plant maintenance and downtime implies that operational labor would be participating in work during plant shut downs. Labor related to operations is estimated according to assumed hourly wages and to the number of operators required for a sequence of process units based on the type of process (solids/fluids) they handle and their throughput. All processes (mining, hydrotreating, etc.) are assumed to require operators 24 hours per day, seven days per week. Operators are paid \$30 per hour on average. Maintenance is estimated as a percentage of C_{TDC}. Literature values range from 2–11.5% of C_{TDC} [11,23] for all of the wages, salaries, and benefits paid to maintenance labor as well as the required materials, services and overhead. In this report, maintenance is assumed to be 5% of C_{TDC}. In addition to operators and maintenance personnel, a team of process engineers is required. The salaries for all process engineers, \$52,000 per engineer per shift per year, are accounted for under the category of technical assistance to manufacturing. Additionally, workers in the control laboratory are budgeted at \$57,000 per operator per shift per year. Finally, management, including accounting and business services, supervisors, human relations, and the mechanical department, is budgeted as operating overhead based on specific percentages of the total salaries, wages and benefits of the operators, maintenance personnel, lab personnel and engineers.

Property taxes and insurance are assumed to be a percentage of C_{TPI}. These and other fixed costs are defined in Table 5-8. Note that property taxes, insurance, and general expenses are calculated for the project as a whole, but the other fixed costs given in Table 5-8 are calculated for each unit operation separately (to account for the differences in materials processed in each unit).

Table 5-8. Fixed costs included in scenario analyses; modified from Seider et al. [11].

Cost	Method of calculation
Labor for operations	
Wages and benefits (*LW*)	*LW* = $30/operator-hour
Salary and benefits (*LS*)	*LS* = 15% of *LW*
Operating supplies and services	6% of *LW*
Technical assistance to manufacturing	$52,000/(operator/shift)/year
Control laboratory	$57,000/(operator/shift)/year
Maintenance (*M*)	
Wages and benefits (*MW*)	43.48% of *M*
Salary and benefits (*MS*)	10.87% of *M*
Materials and services	43.48% of *M*
Maintenance overhead	2.17% of *M*
Operating overhead	
General plant overhead	7.1% of (*LW* + *LS* + *MW* + *MS*)
Mechanical department services	2.4% of (*LW* + *LS* + *MW* + *MS*)
Employee relations department	5.9% of (*LW* + *LS* + *MW* + *MS*)
Business services	7.4% of (*LW* + *LS* + *MW* + *MS*)
Property tax	1.0% of C_{TPI}
Insurance	0.4% of C_{TPI}
General expenses	
Administrative expense	$200,000/(20 employees)/year
Management incentive compensation	1.25% of net profit

5.4.3 Corporate Tax, Royalties and Severance Tax

Descriptions of the various taxes and royalties applying to unconventional fuel development were provided in Section 3.4. The information in this section provides a summary of how those taxes and royalties are applied to the scenarios analyzed for this report.

5.4.3.1 Royalty, Bonus, and Rental Payments

Oil royalties for all scenarios are calculated according to the Equation (5.9):

$$R_n = r_n S_{oil,n} \tag{5.9}$$

where n is the year of the project, r_n is the royalty rate for a given year, and $S_{oil,n}$ is oil sales for a given year. Royalty rates are calculated based on the entity from which the land under development is leased. The oil shale scenarios are located on federal (BLM) lands while the oil sands scenarios are located on state (SITLA) lands.

Royalty rates applying to oil shale development on BLM lands are unsettled (see Section 3.4.1.1), so the 2008 proposed rates are used in this report, e.g. 5% for the first five years of the lease followed by a rate increase of 1% per year up to 12.5%. Royalty rates on SITLA leases (both oil shale and oil sands) start at a rate of 8% of oil sales for the first ten years of the lease. Assuming that the oil shale leases are acquired during the second year of the respective projects (2013) and that the date of acquisition is the start of the introductory rate period, the first rate hike of 1% occurs in 2018. Each year thereafter the rate increases by another 1% until the maximum rate of 12.5% is reached in 2025, where it remains for the remainder of the project. The acquisition of oil sands leases also occurs during the second year of the project (2013), which is the start of the introductory rate period. The first rate hike of 1% occurs in 2023 with the rate increasing by 1% per year thereafter until the maximum rate of 12.5% is reached in 2026, where it remains for the project's duration. Transportation deductions are assumed to be negligible and are not included in Equation (5.9).

Bonus and rental payments are not specifically calculated. Instead, they are assumed to be covered by the costs of mineral leases (C_L), which is defined as 2% of C_{TDC}. Given the large costs for mining, drilling, and processing equipment included in C_{TDC}, the resulting values of C_L are on the order of tens of millions of dollars. For comparison, the entire SITLA income (including severance taxes, royalties, lease sales, etc.) for all oil and gas development in the state of Utah during FY 2010 was $56 million dollars [38]. Hence, a one-time expense of 2% of C_{TDC} should be more than sufficient to cover bonus and rental payments to either state or federal landowners.

In 2010, the average oil production rate was 68,000 BPD [39] and the average gas production rate was 1.2 billion SCF per day [40].

5.4.3.2 Severance, Corporate, and Property Taxes

Severance taxes are calculated based on the "taxable value" (TV) of the oil at the wellhead. As discussed in Section 3.4.2.1, the TV of the oil is determined by estimating the value of the oil at the wellhead and deducting costs for transportation, processing, and oil royalties. However, the determination of the TV for unconventional resources is more complex than traditional oil and gas production. As a result, this report interprets the rules regarding severance taxes as follows.

First, the "wellhead" for all scenarios is the point at which a raw shale oil or bitumen has been extracted from a resource and is immediately prior to upgrading. The value of the oil at this wellhead (WV) is assumed to be fraction of that of WTI based on its API gravity, as given by Equation (5.10):

$$WV = \frac{(API\ gravity\ of\ wellhead\ product)}{(API\ gravity\ of\ WTI)}(Sale\ price\ of\ WTI) \tag{5.10}$$

The *TV* is then the *WV* less deductions for oil royalty payments (*R*), processing costs, and transportation costs. Conventional oil processing costs are typically for minor expenses such as sediment removal. While there are clearly extensive processing costs associated with extracting oil from sand or shale, it is not clear what processing costs would be deductible. Hence, this report makes the conservative assumption that there are no processing deductions. As stated previously, transportation costs were determined to be negligible and are also ignored. Therefore, the *TV* of the oil is given by:

$$TV = WV - R \tag{5.11}$$

where *R* is on a dollar per barrel basis.

The severance tax rate (r_{ST}) applied varies according to the magnitude of the *TV*. The first $13/bbl is taxed at a rate of 3%; additional value above $13/bbl is taxed at a rate of 5%. An additional 0.2% of the total *TV* is taxed for as a conservation fee (r_{cf}). This set of tax rules is implemented using Equation (5.12):

$$ST = [r_{ST=3\%}(1 - f_{ST}) + r_{ST=5\%} f_{ST}]TV + r_{cf}TV \tag{5.12}$$

where *ST* is the severance tax due to the state on a dollar per barrel basis and f_{ST} is the fraction of *TV* above $13/bbl.

Equation (5.12) is then multiplied by the total number of barrels of upgraded product produced in a given year to determine the total severance tax liability during that year. This calculation produces a small over-estimation of the severance tax liability as the volume of upgraded oil is slightly larger than that of the produced oil at the wellhead. While existing law states that no severance taxes are to be incurred until at least 2016, this exemption does not apply to the scenarios in this report as the first year of startup is 2016.

Upgrading reduces the density of the extracted oil, which increases the volume.

Corporate income taxes at the state and federal levels are 5% and 35%, respectively, of taxable income (*TI*), defined as:

$$TI = P(S - C_V - d) - C_F - D - R - ST \tag{5.13}$$

where *d* is depletion and all other variables are as defined previously. Cost depletion is used to determine *d*. The depletion charge in any given year is the number of barrels of oil extracted that year multiplied by the depletion factor p_t. It is assumed that p_t given by:

$$p_t = \frac{C_L}{\text{Total planned oil production}} \tag{5.14}$$

A ten-year Modified Accelerated Cost Recovery System (MACRS) method is used for calculating depreciation [11], with the first depreciation charge occurring in 2016 (the first year of startup) and the last occurring in 2026.

Since state corporate income taxes (T_S) are deductible from federal corporate income taxes (T_F), the total corporate tax liability is given by:

$$T_S = t_S TI \tag{5.15}$$

$$T_F = t_F(TI - T_S) \tag{5.16}$$

where t_S and t_F are the respective state and federal corporate tax rates.

Property tax is assumed to be 1% of C_{TPI} and is accounted for as a fixed cost. The total tax liability used in Equation (5.1) is therefore the sum of the severance and state/federal corporate income taxes:

$$T = ST + T_S + T_F \tag{5.17}$$

5.5 State Tax Credit

The newly enacted Utah alternative energy development tax credit discussed in Section 3.4.4 is not considered as part of the "base case" analysis in the unconventional fuels development scenarios that follow. Rather, its effect is reported as part of the sensitivity analysis that examines the effect on supply price of various parameters, including tax policy.

To compute the tax credit of 60% of "new state revenues," employee earnings (wages plus benefits) are estimated based on the labor requirements of each scenario and then an effective tax rate of 2.8% is applied. This "new" personal income tax revenue stream for the state is added to the state corporate income tax owed (5% of taxable income). The tax credit is then assumed to be 60% of this total (see Equation (3.1)). For years when the tax credit exceeds the state taxes owed, the overage amount is rolled over to the next tax year as a credit. Table 5-9 illustrates the application of the tax credit to the state corporate income tax liability for the ex situ oil shale scenario described in Section 6. The effect of the tax credit is to reduce the tax rate to 0% for the first three years when taxes are paid (years 8, 9, and 10 of the project). The tax rate then slowly increases to 1.6% of taxable income in the final years of the project.

Table 5-9. Utah state tax credit as applied to the ex situ oil shale scenario (see Section 6).

Year	Base State Tax	Tax Credit	Credit Balance	Final State Tax
2012	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -
2014	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -
2016	$ -	$ 1,371,657.50	$ 1,371,657.50	$ -
2017	$ -	$ 1,371,657.50	$ 2,743,315.01	$ -
2018	$ -	$ 1,371,657.50	$ 4,114,972.51	$ -
2019	$ -	$ 1,371,657.50	$ 5,486,630.02	$ -
2020	$ 3,980,732.59	$ 3,760,097.06	$ 5,265,994.48	$ -
2021	$ 7,217,270.17	$ 5,702,019.61	$ 3,750,743.92	$ -
2022	$ 8,400,267.45	$ 6,411,817.97	$ 1,762,294.44	$ -
2023	$ 8,020,410.82	$ 6,183,904.00	$ -	$ 1,836,506.82
2024	$ 7,618,708.82	$ 5,942,882.80	$ -	$ 1,675,826.03
2025	$ 7,547,366.05	$ 5,900,077.13	$ -	$ 1,647,288.92
2026	$ 13,438,691.24	$ 9,434,872.25	$ -	$ 4,003,818.99
2027	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2028	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2029	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2030	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2031	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2032	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2033	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2034	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79
2035	$ 19,142,385.75	$ 12,857,088.95	$ -	$ 6,285,296.79

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6 *Ex Situ Oil Shale Production Scenario*

6 Ex Situ Oil Shale Production Scenario

This section provides a profitability analysis for producing SCO from Utah oil shale using an ex situ extraction process, e.g. mining and surface retorting, at a production capacity of 50,000 BPD. A location for this scenario was chosen based on work recently completed by UGS to describe Uinta Basin oil shale resources [1]. Figure 6.1 is an isopach map illustrating how the thickness of the 25 GPT oil shale zone varies across the basin; the blue lines are depths to the top of this zone. Based on this map, the most promising area for oil shale development is the northeast section of the Uinta Basin. In this area, the depth of the top of the 25 GPT zone varies from 500 to 1,000 feet (152–305 meters) and the thickness of the zone is 60 to 130 feet (18–40 meters), suggesting underground mining as the most commercially viable ex situ extraction method.

An isopach is a contour connecting zones of equal thickness.

The mine is located on the 60–100 feet (18–30.5 meters) isopach contours

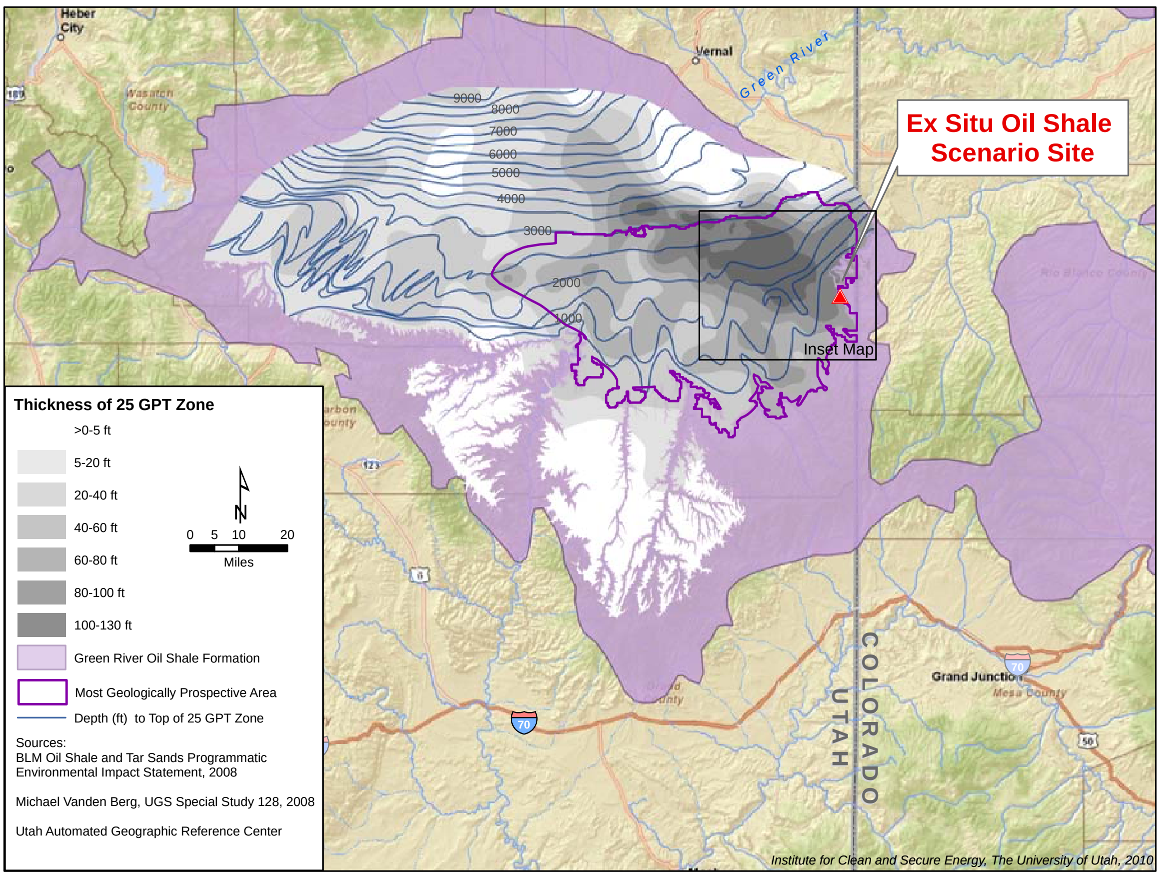

Figure 6.1: Isopach and overburden thickness for 25 GPT oil shale with location of ex situ oil scenario identified; adapted from [1].

An inset map of the area delineated by the square in Figure 6.2 is shown in Figure 6.2. The scenario is located on federal (BLM) land, so the federal government is the landowner for the purposes of determining tax and royalty payments; see Section 3.4. Land ownership in this northeast section of the Uinta Basin is a mix of federal, state, tribal, and private land. The pattern of land ownership seen in Figure 6.2 illustrates the threshold complications confronting any large-scale development.

These complications include obtaining necessary rights of way for resource access and managing development activities across a variety of jurisdictional and administrative boundaries while effectively mitigating the environmental impacts of those activities.

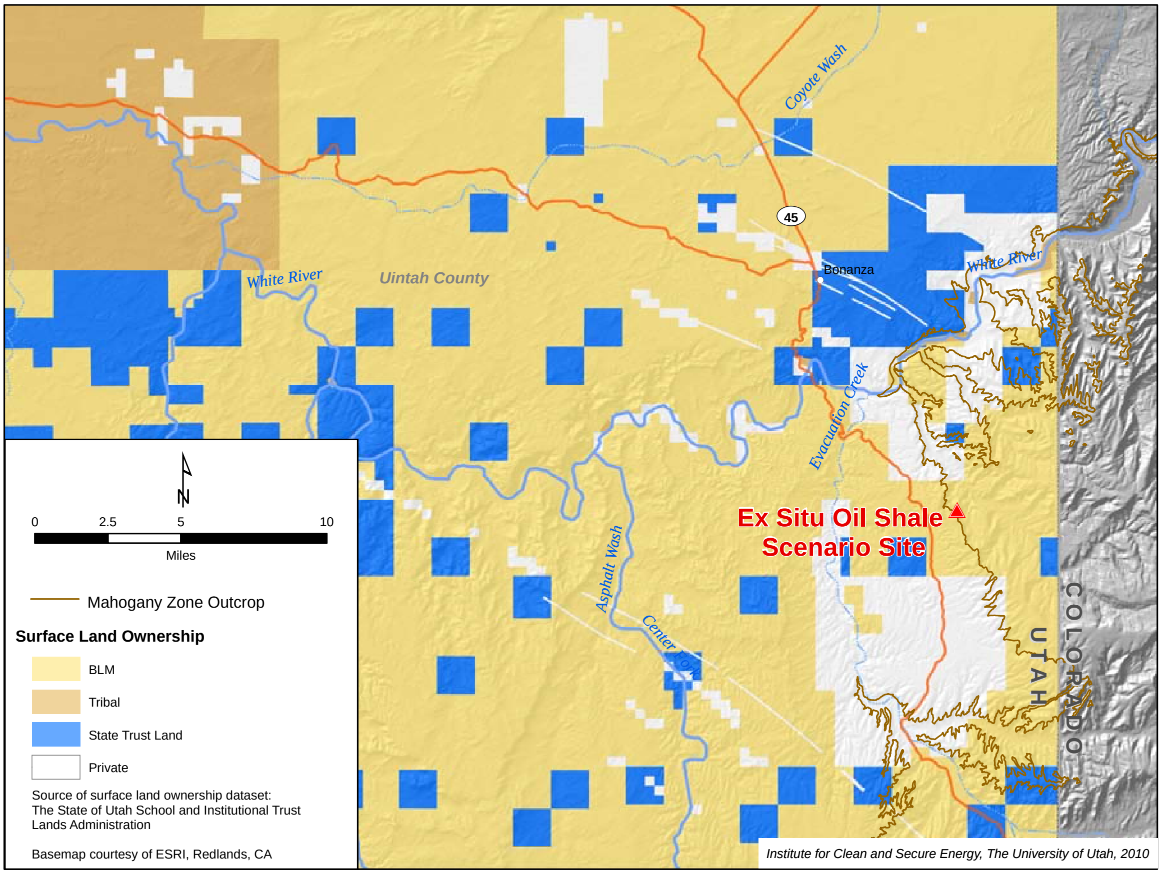

Figure 6.2: Land ownership in the northeast Uinta Basin near the ex situ oil shale scenario site.

An example of the oil yield as a function of depth is plotted in Figure 6.3. The oil yield is estimated by bulk density from a well drilled in the northeast section of the Uinta Basin. The rich oil shale layers are thin and interspersed with lower grade or lean layers. The oil content of the rich layers reaches 80 GPT while the lower grade layers are in the neighborhood of 10 GPT. In this area of the basin, the average oil shale grade of the Mahogany zone (R-7) is roughly 25 GPT.

The Mahogany zone is the target of mining and retorting operations.

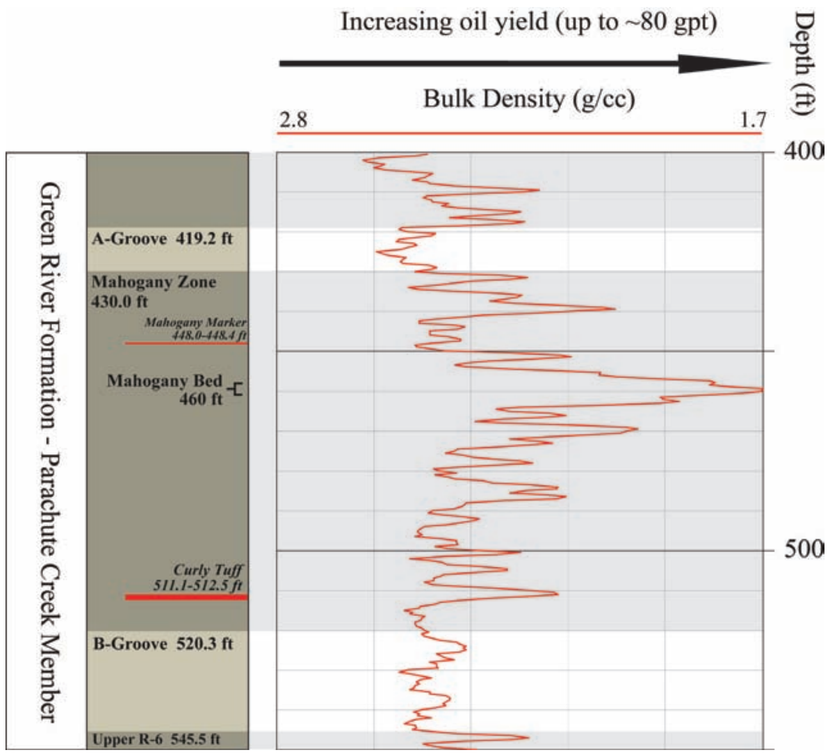

Figure 6.3: Bulk density logs showing oil yield as a function of depth through the Mahogany zone of the Uinta Green River Formation. Figure courtesy of Michael Vanden Berg, UGS.

Bulk density units are grams per cubic centimeter (g/cc) and depth units are feet (ft).

6.1 Description of Unit Operations

The overall ex situ oil shale production scenario is shown in Figure 6.4. To supply heat for this scenario, two different combustion systems are considered: air-fired and oxy-fired. Both systems are shown in Figure 6.4; the dashed lines are for processes that only apply to oxy-firing. In the air-fired system, natural gas is combusted with air and the effluent is sent to a stack. In the oxy-fired system, natural gas is combusted with pure oxygen (O_2) that has been mixed with recycled flue gas (RFG).

Flue gas refers to the combustion gases exiting the furnace/heater. RFG is used to control the flame temperature.

Details of each block (e.g. unit operation) in the figure are discussed in the sections below. In order to determine the supply costs for the given production rate of SCO, the individual pieces of major equipment needed for each unit operation are identified and then the capital and operating costs are estimated. Figure 6.4 and by extension this analysis do not include an exhaustive list of all unit operations required for production of SCO from a mining/surface retorting operation. Rather, the intent of this analysis is to show the broad categories of unit operations and equipment that will be required for development at a commercial scale.

Examples of processes that are not specifically mentioned include oil/water separation and filtering of solids from the raw shale oil.

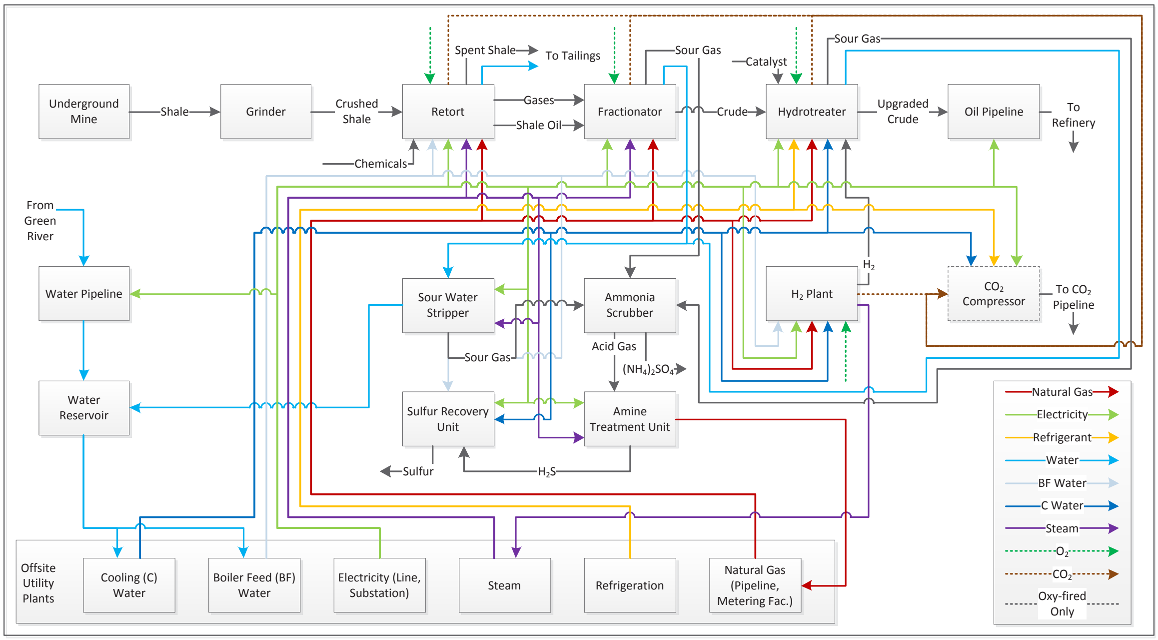

Figure 6.4: Ex situ oil shale production process overview.

Two retorting technologies were selected for this report, Tosco II and Paraho Direct. Tosco II technology was selected because details of operating requirements were available in Weiss et al. [2]. Paraho technology was selected because of current commercial development by Shale Tech International and the availability of some cost and operating data [3,4]. Oxy-firing technology is considered for the Tosco II process only; insufficient data does not allow the analysis of oxy-firing costs for the Paraho Direct process.

A pilot scale plant employing the Tosco II process was built in 1974; it processed up to 1,000 tons per day (TPD) or 907 metric tons per day (MTPD) of oil shale [5]. Two Paraho processing plants were also completed in 1974. The larger of the two processed 270 TPD (245 MTPD) of oil shale [3].

Unless otherwise noted, all unit operations are located at the scenario site near Bonanza, Utah.

6.1.1 Mining

The extraction of oil shale starts between 500 and 1000 feet (152–305 meters) down in an underground mine. Two vertical shafts, each approximately 30 feet (9.1 meters) in diameter, are constructed to a depth of 1000 feet (305 meters). Each shaft will be continuously lined (except for station openings) with 12 inches (0.3 meters) of poured concrete. One shaft is used for ore production while the other is a service shaft for men and materials. The shafts are also used for mine ventilation, the service shaft for air intake and the production shaft for exhaust. The ventilation rate is designed for 300 standard cubic feet per minute (SCFM) based on the use of diesel equipment.

The ore is mined by the room and pillar method, wherein some material must be left as pillars to support the mine roof and all overlying beds. Pillars are approximately 150 by 150 feet (46 meters). A 50-foot (15-meter) mining height, cut in two vertical lifts, is used to meet the design production rates of 25 GPT oil shale: (1) 87,800 TPD (79,700 MTPD) for the Tosco II process and (2) 95,450 TPD (86,600 MTPD) for the Paraho Direct process. Haulage and service drifts connected to the two shafts are nominally 50 feet high by 50 feet wide (15 meters).

A drift is a near-horizontal passageway in a mine, following the bed or vein of a mineral resource [6].

The broken rock obtained after drilling and blasting is hauled with a load-haul-dump unit and delivered to strategic locations where primary crushing of the ore occurs. For the Tosco II process, the crushed ore is then loaded onto conveyors which move the rock to a loading area at the bottom of the production shaft. From there, the crushed ore is hauled to the surface and dumped onto the coarse-ore storage pile. For the Paraho Direct process, the crushed ore is transported via conveyor to an adjoining secondary crusher, which reduces the size of the shale to less than six inches. After secondary crushing, the mined material is transported to the surface via an incline conveyor, where it is distributed by conveyor systems to either tertiary crushing units or an emergency storage pile.

The capital and operating expenses for both the Tosco II and Paraho Direct mines are assumed to be equivalent to the scaled (sixth-tenths rule) mining costs published by Weiss et al. [2] and by Cleveland-Cliffs et al. [3] respectively. Scaling is based on the production volume, the oil shale grade, and time. For the Tosco II process, costs are scaled from a 1981 analysis of a 49,500 BPD facility processing 35 GPT ore. Paraho Direct costs are scaled from a 1976 analysis of a 99,170 BPD facility processing 29 GPT ore.

6.1.2 Size Reduction and Solids Handling

6.1.2.1 Tosco II Process

At the surface, ore from the coarse-ore storage pile is transported via a tunnel reclaim conveyor to a secondary crusher. From the secondary crusher, the rock is conveyed to an enclosed, 15,000-ton intermediate storage facility which provides surge capacity between crushing and retorting.

A tunnel reclaim conveyor is a conveyor system for providing a continuous feed of solid material. The secondary crusher is a 10-unit parallel impact crusher system that reduces the particle size of the ore to less than 0.5 inches (1.3 centimeters), a requirement for the retort.

Ore beneficiation using fine grinding and froth flotation before retorting was studied by Weiss et al. [2] and was not found to be an economic improvement over direct retorting due to the high capital and energy costs for fine grinding as well as the added uncertainty of the process. Grinding technology has not significantly improved since the time of the Weiss report, so ore beneficiation has not been considered in this report.

Beneficiation is the selective removal of kerogen-rich particles from much of the host rock so that less material is retorted.

The capital and operating expenses for the size reduction and solids handling process described above are assumed to be equivalent to the scaled (sixth-tenths rule) mining costs published by Weiss et al. [2].

6.1.2.2 Paraho Direct Process

In addition to crushing, this unit operation also includes screening, fines handling, and conveying via enclosed conveyor systems. Crushed ore from the mine is fed into a double-roll tertiary crushing system which reduces the particle size of the shale to less than three inches. This crushed shale is screened again and material less than 0.375 inches (1 centimeter) is rejected as fines. After this step, material loss and rejected fines account for about 10% of the original mined material (see Table 6-2). The final screened material that meets the proper size classification is transported by conveyor to a prepared shale storage area while the fines are transported to the fines disposal area.

Material smaller than 0.375 inches (1 centimeter) is too small to be processed in the retort.

The capital and operating expenses for the Paraho Direct size reduction and solids handling process are assumed to be equivalent to the scaled (sixth-tenths rule) mining costs published by the Paraho Development Corporation [3].

6.1.3 Surface Retorting

Any one of a number of retort technologies could be used for this case. Capital costs for various retort technologies as a function of retort capacity are shown below in Figure 6.5; the curves were obtained from cost curves in STRAAM [7] and from scaling Weiss et al. [2] and Cleveland-Cliffs et al. [3] data as described in Section 5.4.

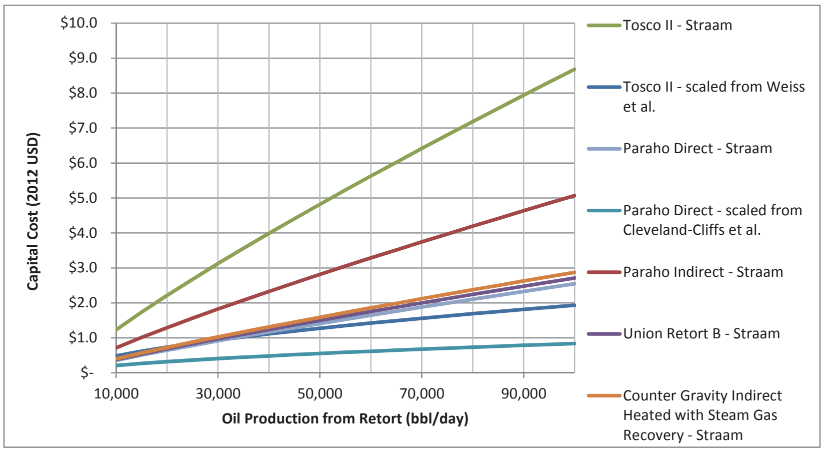

Figure 6.5: Retorting technology capital cost comparison (in 2012 US$) assuming 25 GPT oil shale. Data from STRAAM [7], Weiss et al. [2], and Cleveland-Cliffs et al. [3].

The two capital cost curves for the Tosco II retorting process diverge, as do the two curves for the Paraho Direct process. This divergence is caused by differences in cost estimating methodologies. STRAAM's [7] cost curves are of the form:

$$C = aX^b \tag{6.1}$$

where C is the capital cost, a and b are constants specific to a given retort technology, and X is the oil production capacity of the retort. The scaled costs from Weiss et al. [2] and from Cleveland-Cliffs et al. [3] are given by:

$$C = a(X / X_o)^b \tag{6.2}$$

where X_o is the base oil production capacity and the other variables are the same as for Equation (6.1). STRAAM assumes that b = 0.85, whereas the scaling approach used in this report assumes that b = 0.6. Compared with the STRAAM data, the scaled costs used in this report for both the Tosco II and Paraho Direct retorts are at the lower limit of the capital cost range.

Seider et al. [8] suggest a value of 0.6 for "b" if there is not enough information to choose something else. Williams found that "b" can vary from 0.48 to 0.87 for individual pieces of equipment and from 0.38 to 0.90 for entire plants, but that overall the average value of b was approximately 0.60 [9].

6.1.3.1 Tosco II Retort

The process design of the Tosco II retort is based chiefly on documentation from the Exxon Colony project with scaling for production rate, oil shale grade, and time [2]. The plant has six retorts operating in parallel trains. The process flow diagram for one retort train is shown in Figure 6.6 while the design criteria are listed in Table 6-1.

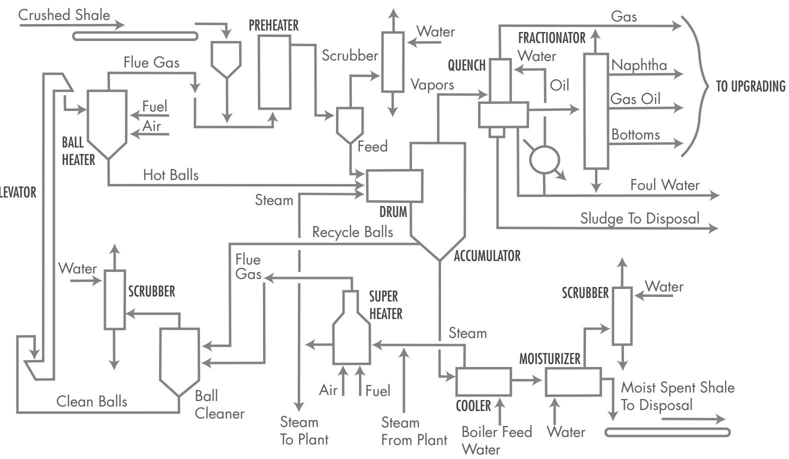

Figure 6.6: Process flow diagram for the Tosco II retort; based on figure from Weiss et al. [2].

Table 6-1. Design criteria for Tosco II surface retort; scaled from Weiss et al. [2].

Item	Value	Units
Material Balance		
Raw shale (25 GPT)	87,800 (79,700)	TPD (MTPD)
Shale oil recovery	90	% of Fischer assay
Moisture		
raw shale	1.4	wt%
spent shale	14	wt%
Fractionation products		
Gas	25.1	wt%
Naptha	10.4	wt%
Gas oil	45.6	wt%
Bottoms oil	18.9	wt%
Retorting temperature	900 (482)	°F (°C)
Spent shale temperature (after moisturizer)	200 (93)	°F (°C)

The crushed, raw shale from the intermediate storage facility is preheated with flue gases from the ball heater and fed into the retort together with steam and hot ceramic balls that act as a heat transfer medium. The retort includes a rotating inclined drum in which the shale and balls are intimately mixed. Retorting decomposes the kerogen in the oil shale to gas, oil, and char. The gas and oil form the overhead vapors while the char remains on the retorted shale. Overhead vapors, including water (H_2O), hydrocarbons (e.g. oil), carbon monoxide (CO), CO_2, NH_3, H_2S, and H_2, are quenched with cooling water and sent to the fractionator.

The gas product from the Tosco II process is assumed to be pure methane.

The spent (retorted) shale is separated from the balls at the bottom of the accumulator and is discharged through a cooler (waste heat recovery boiler) to a moisturizer. The balls are recycled to the retort drum via a cleaner and heater. The moist and cooled spent shale is then taken by conveyor to the waste disposal area. The spent shale contains all the mineral matter that was in the raw shale plus a few percent of unrecoverable kerogen or its non-volatile organic derivatives.

Although Weiss et al. [2] do not give enough information to estimate how much heat is recovered in the cooler, the spent shale is cooled by boiler feed water, producing steam that is sent to the superheater.

In the cleaner, dust is removed from the balls using the flue gases from a steam super heater.

6.1.3.2 Paraho Direct Retort

The process design for the Paraho Direct retort was obtained from (1) a commercial design evaluation [3] and (2) a report detailing process evaluation data [4]. The plant has 12 retorts that are grouped together in batteries of six. Each battery is fed by a single raw shale conveyor. The process flow diagram for one retort is shown in Figure 6.7 while the design criteria are listed in Table 6-2.

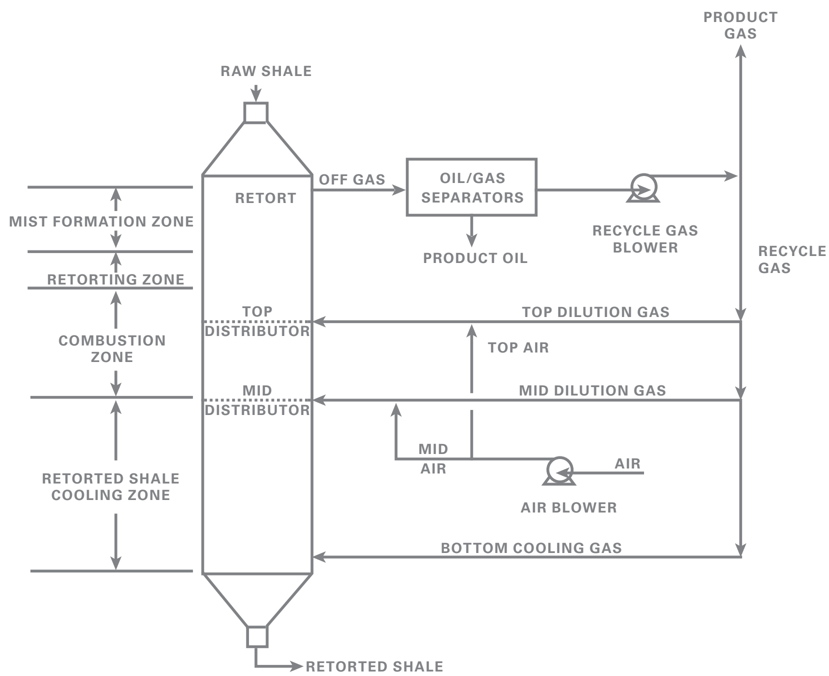

Figure 6.7: Process flow diagram for the Paraho Direct retort; based on figure published by Fuel and Mineral Resources, Inc. [4].

Crushed and screened oil shale from the shale storage area is fed into the top of the vertical Paraho Direct retort. The retort is rectangular in shape with a cross section of 28.4 feet (8.7 meters) by 114.8 feet (35 meters). The active shale bed has a height of 25 feet (7.6 meters) with an overall structure height of 155 feet (47.2 meters). The shale moves downward by gravity through four zones in the retort: mist formation, retorting, combustion, and cooling. Temperature control and heat transfer in the various zones is achieved by a counter-current flow of air and recycle gas injected from top, middle, and bottom air-recycle gas distributors. The downward movement of the shale is controlled by the system's principal moving mechanism, the Paraho grate, located at the bottom of the retort. Internal combustion from both char remaining on the retorted shale and from the recycle gas generates the heat required for retorting. The two heat exchange zones in the retort, mist formation and cooling, reduce heat losses and improve the overall energy efficiency of the retort.

In the mist formation zone, raw shale is preheated by the oil mist. In the retorting zone, solid kerogen is decomposed to gas, oil, and char. The char remaining on the shale is burned in the combustion zone; recycle gas is injected to assure uniform temperature distribution. Retorted shale is cooled by recycle gas in the cooling zone.

Table 6-2. Design criteria for Paraho surface retort; scaled from Cleveland-Cliffs et al. [3].

Item	Value	Units
Material Balance		
Raw shale mined (25 GPT)	95,450 (86,600)	TPD (MTPD)
Raw shale retorted (25 GPT)	85,900 (77,900)	TPD (MTPD)
Shale oil recovery	92	% of Fischer assay
Moisture		
raw shale	2.6	wt%
spent shale	6.9	wt%
Fractionation products		
Gas	24.1	wt%
Naptha	10.5	wt%
Gas oil	46.2	wt%
Bottoms oil	19.2	wt%
Retorting temperature	1200 (649)	°F (°C)
Spent shale temperature (after moisturizer)	295 (146)	°F (°C)

The amount of material actually retorted is less than that mined by 10 wt% because the fines are not sent through the retort.

Oil mist and produced gas are removed near the top of the retort at the off-gas collector for subsequent processing into raw shale oil and a gas product with low Btu content. The temperature of this exiting retort off-gas is approximately 150°F (66°C). The off-gas (consisting of oil mist and produced gas) is routed through a knockout drum, a coalescer, and an electrostatic precipitator. Approximately 99% of the oil mist is removed from the off-gas stream while the low-Btu gas product is routed to gas processing units for subsequent use in the retort [4]. The oil mist is sent to the fractionator. Spent shale exits the bottom of the retort at a temperature of 295°F (146°C). It is then transported by conveyor to the disposal site. A water spray device is used to cool the spent shale only if the spent shale temperature exceeds 400°F (204°C) due to a process malfunction.

The composition of the gas product is given in Table 4-4 of Cleveland-Cliffs et al. [3].

6.1.4 Fractionation

The fractionator is an atmospheric distillation column that separates the condensed hydrocarbon vapors and various gases (CO, CO_2, NH_3, H_2S, H_2O, and H_2) coming from the retort into the following streams:

- Sour gases
- Fouled water
- Naptha - hydrocarbons with a boiling range of 100°–400°F (38°–204°C)
- Vacuum Gas Oil (VGO) - hydrocarbons with a boiling range of 400°–950°F (204°–510°C)
- Wax - hydrocarbons with a boiling range > 950°F (510°C)

The three different distillation cuts (naptha, VGO, and wax) comprise the shale oil product from the retort. These distillation cuts are stored in heated surge tanks until they are moved to the hydrotreater for upgrading. Sour gases and fouled water are sent to the ammonia scrubber and sour water stripper,

Other feed pretreatment steps such as olefin and metal removal are not considered in this analysis.

respectively, where these streams are cleaned up for use elsewhere in the process. Capital and operating costs for the fractionator are scaled from data given by Maples [10].

A sour gas, also known as an acid gas, is acidic due to high quantities of H_2S and/or CO_2 in the gas. Sour water, also known as fouled water, typically contains H_2S and NH_3.

6.1.5 Primary Upgrading

Primary upgrading involves molecular weight reduction while secondary upgrading removes impurities and increases the API gravity of the oil. Shale oil produced from surface retorts such as the Tosco II or Paraho Direct requires only secondary upgrading to reduce its aromatic, nitrogen, sulfur and heavy metal content.

6.1.6 Secondary Upgrading

The secondary upgrading process of hydrotreating, depicted in Figure 6.8, takes place in catalytic reactors where H_2 is reacted with the various distillate cuts comprising the shale oil. Each of the distillate cuts is hydrotreated separately using different reactors. Aromatic components of the oil are converted to aliphatic components, nitrogen to NH_3, and sulfur to H_2S. Heavy metals are confined to the coke residue. The distillate cuts are assumed to have the same fixed composition for all scenarios; process conditions and catalysts used are also the same across scenarios.

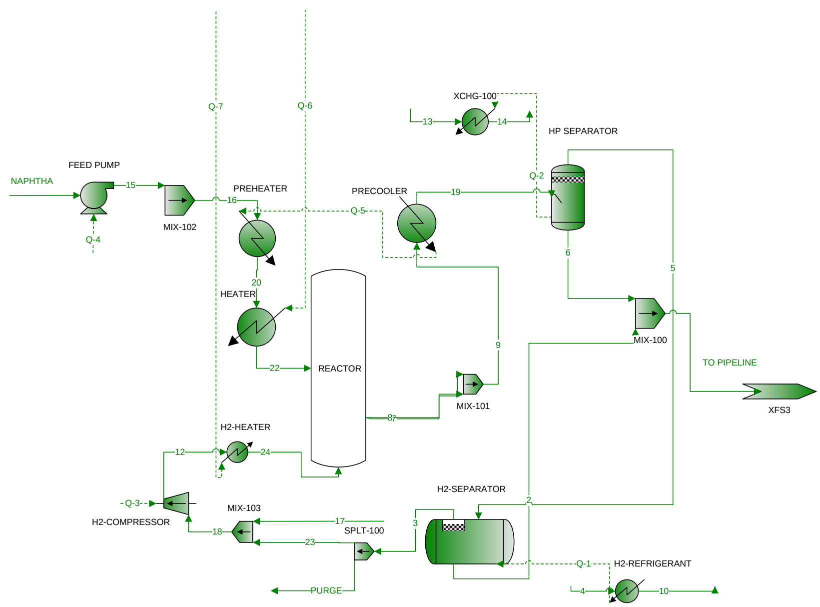

Figure 6.8: Hydrotreating configuration developed in ProMax by Castro for naphtha distillate cut [11].

ProMax process simulation software is used to model the hydrotreater. ProMax calculates the mass balances (species compositions, flow rates, reactions, etc.), energy balances (heating, cooling, pumping, etc.), and size of each piece of process equipment shown in Figure 6.8. An oil distillate cut (in this case, naptha) is pumped from storage and passed through a feed preheater to raise its temperature to reactor entrance conditions (842°F or 450°C). The heated oil enters the top of the trickle-bed catalytic reactor, trickling down through the catalyst and reacting with H_2 to form saturated hydrocarbons. Unreacted

A catalyst is a substance present in small quantities that increases the rate of a chemical reaction while not being consumed in the chemical reaction.

H_2 is separated from the oil product and recycled through the reactor again with a small amount of fresh H_2 feed. The reaction products [12] are given by:

$$Feed + H_2 \xrightarrow{Catalyst} SaturatedHydrocarbons + H_2S + NH_3 + H_2 \qquad (6.3)$$

Consumption of H_2 in the hydrotreater is determined to be 2,000 SCF (57 cubic meters)per barrel of oil based on H_2 consumption data from pilot plant-scale hydrotreating tests conducted on Colorado shale oil; see Figure 2 in Sullivan and Stangeland [13]. Hydrogen needed for the hydrotreater is provided by the hydrogen plant discussed in section 6.1.7.

H_2 consumption of 2,000 SCF is equivalent to 56.7 cubic meters or 4.67 kilograms of H_2.

Gaseous byproducts (H_2S and NH_3) are removed from the hydrotreating unit in the purge stream which is sent to the ammonia scrubber as described in Section 6.1.8. A sour water stripping unit is also included to remove these same byproducts from the hydrotreater's recycled cooling water; see Section 6.1.11. The annual production of H_2S is estimated to be 20,045 tons (18,200 metric tons) and that of NH_3 to be 49,000 tons (44,500 metric tons).

Heat requirements for the catalytic reactors (at least one for each distillate cut stream) are supplied by a natural gas combustion system. Heat integration is used to lower process energy requirements. After the reactor, the gas stream passes through a flash unit to remove condensable gases (mostly H_2) that are recycled back to the reactor. The upgraded oil is cooled down and sent to storage awaiting pipeline transportation.

Since detailed process flowsheet information is available for this component of the oil shale production scenario, the method of Guthrie is used for costing each piece of equipment shown in Figure 6.8. Additional information, including mass and energy flows associated with the hydrotreater, can be found in Castro [11].

The properties of the raw and upgraded shale oil are given in Table 6-3. The published properties of raw shale oil from Tosco II and Paraho Direct retorts are very similar [3,14], so the average properties shown in the table are used for sizing the hydrotreating facilities needed for both processes. The upgraded shale oil is of high quality: 38°API, a low pour point, and low concentrations of sulfur, nitrogen and heavy metals. Table 6-3 also shows a direct comparison between the upgraded shale oil and three common reference crude oils: WTI, Brent Crude, and Arabian Light Crude.

Table 6-3. Properties of raw and upgraded shale oil [3,14] in comparison to three benchmark crudes [15,16].

vol% = Volume percent

		Raw Shale Oil	Upgraded Shale Oil	West Texas Intermediate	Brent Crude	Arabian Light Crude
Oil Properties	API Gravity	20	38.0	39.6	38	34
	Sulfur (wt%)	0.7	0.01	0.24	0.37	1.7
	Nitrogen (wt%)	1.9	0.1		0.1	0.07
	Pour Point (°F)	70	0	-18	45	-10
	Solids (wt%)	1 - 2				
Distillate Cuts	Boiling Range (°F)	(vol %)				
Naptha	100 - 400			56		
	104 - 800	54	73		78	67
Vacuum Gas Oil	400 - 950			32		
	800 +	45	26		21.7	32
Wax	950 +			9		
	1000 +	7	2		10.2	17

6.1.7 Hydrogen Plant

Based on the 2000 SCF (57 cubic meters) of H_2 per barrel of raw shale oil required for upgrading [13,14], approximately 94 million SCF (2.66 million cubic meters) of H_2 are required per day to upgrade the shale oil produced in this scenario. For this volume of gas, a hydrogen plant is required.

A common source of H_2 is natural gas. It can be converted to H_2 and CO by either methane steam reforming or gasification, each of which has advantages and disadvantages. Advantages of steam reforming include: (1) because it uses H_2O rather than O_2 as a reactant in the catalytic reaction, the desired products (CO and H_2) are not consumed, resulting in greater product yields; (2) the steam reforming process generates three moles of H_2 per mole of methane while the gasification process only generates two moles of H_2. Advantages of gasification include: (1) it is an exothermic process while steam reforming is endothermic, so energy liberated during gasification can be used elsewhere while the steam reforming process requires large amounts of energy to power the reaction to completion; (2) it takes advantage of the larger hydrocarbons present in the natural gas feed stream (ethane, propane, butane, etc.) to create more CO and H_2 while steam reforming does not.

Natural gas is comprised primarily of methane, but it can contain small amounts of ethane, propane, butane, pentane, and CO_2.

An exothermic reaction releases heat. An endothermic reaction requires heat or the reaction will not occur.

An economic analysis was undertaken to determine which process was more cost effective. This analysis assumed that natural gas was pure methane, that no side reactions occurred, and that energy for the steam reforming process came from natural gas combustion. For gasification, the cost was $7.30 per pound ($3.31 per kilogram) of H_2 while for steam reforming, the cost was $6.31 per pound ($2.86 per kilogram). Hence, despite its endothermic nature, steam reforming is more cost effective.

The O_2 needed for gasification must be of high purity and is very expensive.

Thus, the hydrogen plant in this scenario utilizes the steam reforming process coupled with a water-gas shift process to produce H_2 for the hydrotreater. A schematic of the hydrogen plant is shown in Figure 6.9.

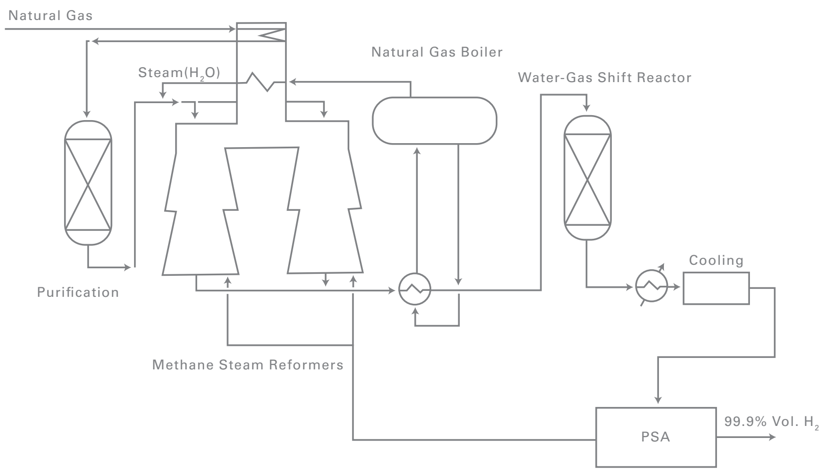

Figure 6.9: Hydrogen production system from Fleshman [17].

Methane feed is preheated using waste heat from the steam reformer and then purified by passing it through an adsorber column to remove any contaminants such as H_2S. The purified methane is then mixed with steam and fed through catalyst tubes in the reformer to generate H_2 by the steam reforming reaction:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \quad \textbf{(6.4)}$$

This reaction is endothermic and requires a large amount of heat. That heat comes from the combustion of natural gas and tail gases (H_2, CO, CH_4, CO_2, and H_2O) from the pressure swing adsorption (PSA) unit. The byproduct CO is used to produce addition H_2 in the water-gas shift reactor:

PSA is a cyclic process that uses solid adsorbent beds to remove impurities from the H_2 gas.

$$CO + H_2O \rightarrow CO_2 + H_2 \quad \textbf{(6.5)}$$

Heat in the gases leaving the steam reformer is used to generate the steam required as a feed to the reformer.

This reaction is slightly exothermic. While water-gas shift reactions are typically carried out in two stages with a high (662°F or 350°C) and a low (392°F or 200°C) temperature step [17], in this work acceptable levels of CO conversion were achieved with only the high temperature step.

Heat exchangers cool the raw gas stream, generating more steam. Some of the CO_2 and H_2O are scrubbed (e.g. removed) in a wet scrubber with a weak base.

Following the water-gas shift reactor, the raw gas stream is cooled and scrubbed prior to entering the PSA. The PSA produces an H_2 product stream that is 99.9% pure and contains 50% of the H_2 present in the inlet raw H_2 stream. The waste gas stream from the PSA containing the other 50% of the H_2 and other tail gases are sent back to the steam reformer for combustion. For additional details, including the catalysts employed in the reformer and in the shift reactor, see Fleshman [17].

The mixture of H_2, unreacted CH_4, and CO is known as syngas.

This PSA-based H_2 production system produces significant amounts of excess steam generated from various heat exchangers. In the present analysis, the steam that is generated is sold back to the off-site steam utility at 50% of the cost of purchasing high pressure (600 psig, 700°F) steam.

The entire ex situ oil shale production/upgrading process requires 10.7 billion pounds (4.85 billion kilograms) of steam and produces 7.2 billion pounds (3.3 billion kilograms) of steam per year.

Fleshman [17] provides detailed capital and utilities utilization for a PSA-based H_2 production system. Using the economic and engineering scaling factors discussed in Section 5 on this data, the capital and operating costs for the hydrogen plant are determined in the same way as the capital and operating costs for mining and retorting.

6.1.8 Ammonia Scrubber

Because sour gases separated from the fractionator and generated as byproducts in the hydrotreater also contain NH_3, they are fed to a wet scrubber with dilute sulfuric acid. The NH_3 passing through the scrubber reacts with the acid to form ammonium sulfate (a fertilizer):

$$2NH_3 + H_2SO_4 \rightarrow (NH_4)_2SO_4 \tag{6.7}$$

After passing through the ammonia scrubbers, the waste gas stream is sent to the amine treatment unit for H_2S removal as described in Section 6.1.9.

Based on the amount of NH_3 produced by the hydrotreater, approximately 191,000 tons (173,000 metric tons) of ammonium sulfate are generated by the scrubbers annually.

For all the scenarios in this report, it is assumed that capital and operating expenses for the ammonia scrubber are offset by ammonium sulfate sales. Hence, both are neglected in the cash flow analysis.

6.1.9 Amine Treatment Unit

Acid ("sour") gases are scrubbed from the waste gas streams by contacting the gas stream with an amine, e.g. diethanol amine (DEA), in an absorber column. The amine reacts with acid gases such as H_2S to produce a water soluble salt:

$$(OHCH_2CH_2)_2NH + H_2S \leftrightarrow (OHCH_2CH_2)_2NH_2^+HS^- + Heat \tag{6.8}$$

This reaction is reversed in the amine regeneration column to produce a concentrated acid gas stream which is then sent to the sulfur recovery unit; see Section 6.1.10. The cleaned gas streams are burned elsewhere in the process to recover their heating value, thus reducing the volume of natural gas that must be purchased. Inputs and outputs to the amine treatment unit are shown as part of the production process overview in Figure 6.4. Capital and operating costs for the amine treatment unit are scaled from data in Maples [10].

6.1.10 Sulfur Recovery Unit

Elemental sulfur is recovered from the acid gas waste stream in the sulfur recovery unit using the Claus process, which involves the following chemical reactions:

$$H_2S + 1.5O_2 \rightarrow SO_2 + H_2O \tag{6.9}$$

$$2H_2S + SO_2 \xrightarrow{Catalyst} 3S + 2H_2O \tag{6.10}$$

In the first step, only one-third of the H_2S in the acid gas stream is burned in a thermal reactor (Equation (6.9)) to produce a stoichiometric mixture of H_2S and sulfur dioxide (SO_2). This mixture is then passed over a catalyst (Equation (6.10)), forming gaseous elemental sulfur (S) that is removed by condensation. By reheating the gas stream after condensation and passing the gases over another catalyst bed, this process can be repeated up to four times to achieve sulfur recoveries of up to 98% [10]. Inputs and outputs to the sulfur recovery unit are shown as part of the production process overview in Figure 6.4.

The amount of H_2S that forms SO_2 is controlled by limiting the amount of O_2 present.

Capital and operating costs for the sulfur recovery unit are scaled from data in Maples [10]. In the present analysis, a sulfur recovery rate of 95% is assumed

Sulfur recovery rates of 94–96% are typical [19,20].

and all sulfur recovered is sold at market prices as reported by USGS [18]. Annual sulfur production is estimated to be 18,000 tons (16,300 metric tons).

6.1.11 Sour Water Stripper

Fouled water from the fractionator and recycled cooling water from the hydrotreater is processed through a sour water stripper to remove any NH_3, H_2S, or other dissolved contaminants that have collected in the water. Contaminants are removed from the water in a stripping column using steam generated from the sour water itself. Any acid gases removed from the water are sent to the ammonia scrubbers described in Section 6.1.8. Inputs and outputs to the stripper unit are shown in Figure 6.4.

Capital and operating costs for the sour water stripper are scaled from data in Maples [10]. Stripped water is then sent to the water reservoir (see Section 6.2.3) for reuse.

6.1.12 Delivery via Pipeline

A pipeline is needed to send the upgraded shale oil to market. The upgraded oil is taken from the storage tanks at the upgrader near Bonanza, Utah and sent through a pipeline to North Salt Lake City; the total estimated length pipeline length is 177 miles (285 kilometers). The pipeline is assumed to follow the path shown in Figure 6.10, which is based on the path taken by Chevron's oil pipeline from the Uinta Basin to the North Salt Lake refineries.

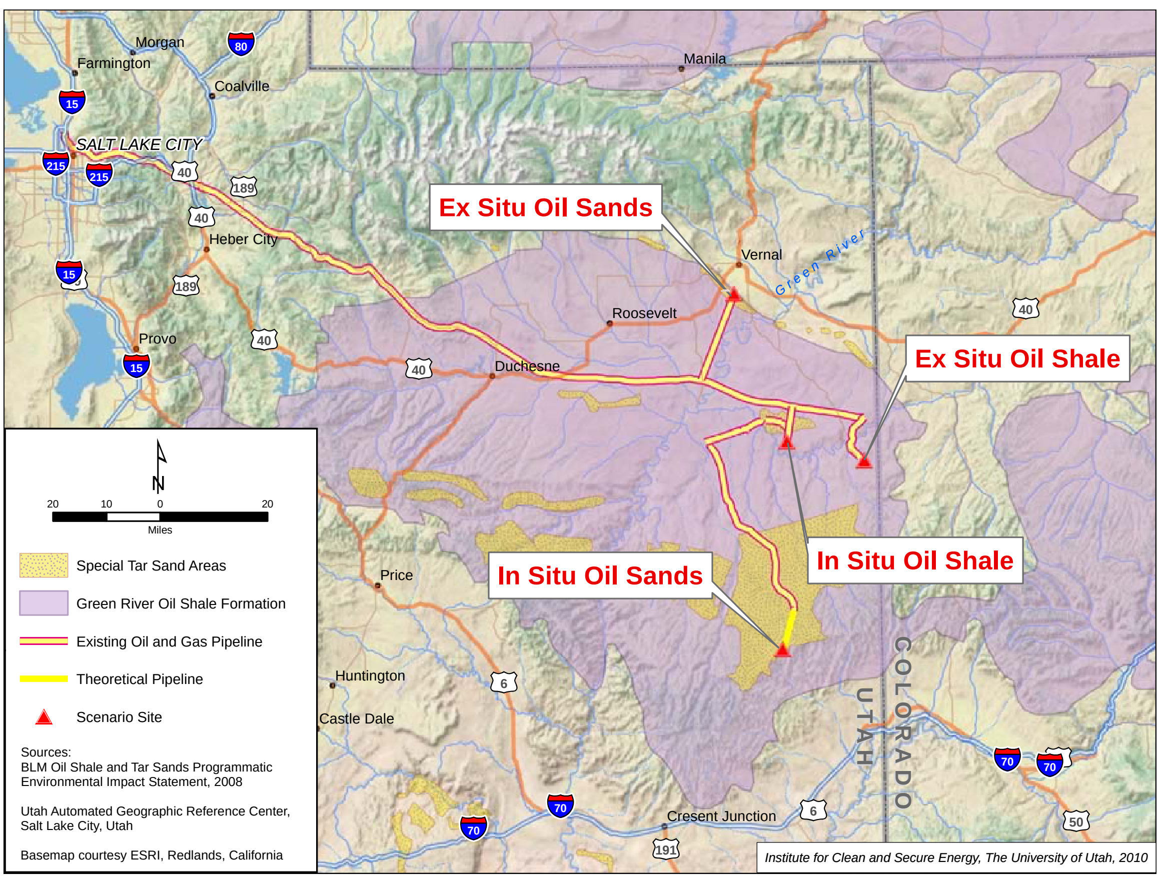

Figure 6.10: Pipeline routes for the Uinta Basin oil shale and oil sands development scenarios.

The inlet and outlet pipeline pressures are assumed to be atmospheric; the oil temperature is assumed to be 68°F (20°C). The pipe is buried three feet underground. The pipe material is Carbon Steel A134. From the properties of the upgraded oil and the transportation route, an economical pipeline diameter of 9.1 inches (23 centimeters) was computed by optimizing the pumping requirements and costs using the method of Peters and Timmerhaus [21]. The pumping requirements were calculated to overcome inclination, friction and oil hold ups. The capital costs for constructing the pipeline and pumping stations are estimated following the methodology used by Boyle [22].

Oil hold up is the volume of oil held in the pipe.

6.1.13 Cost of Utilities

The utilities required for this ex situ oil shale scenario are numerous and the prices for those utilities must be estimated. As described in Section 5.4.2, utility pricing for this scenario uses the constant set price method except when EIA price forecasts are used to estimate oil sales. In those cases, EIA price forecasts for natural gas and electricity are also used [23]. A list of utilities and their prices is given in Table 5-7. The list includes natural gas; electricity; process, cooling and boiler feed water; chemicals; steam; O_2; and refrigerant.

Natural gas and electricity will be brought in to the site from the closest hubs, which are assumed to be located outside Bonanza, Utah, a distance of approximately seven miles (11 kilometers). Water for plant needs is pumped five miles (8 kilometers) from the White River via pipeline to a reservoir at the plant site. Raw water is taken from the reservoir (see Section 6.2.4) to the water pre-treatment facility, where filtration and chemical treatments needed for process, cooling and boiler feed waters are performed. The chemicals needed for water treatment and for other purposes are trucked in and stored in a warehouse.

Three other required utilities, namely steam, refrigeration, and O_2 (for oxy-firing scenarios), are purchased from off-site utility plants at the per unit cost given in Table 5-7. The capital costs for constructing the steam, water treatment, and refrigeration plants are incurred by the project owner. These costs are estimated from Seider et al. [8] and are listed in Table 5-5 under allocated costs for utility plants. Other than capital costs for construction, all of the costs/externalities of the utilities are assumed to be covered by the prices charged in Table 5-7.

With oxy-firing, refrigeration is used to a much greater degree because the effluent gases must be cooled to cryogenic conditions; see Section 6.2.3.

Capital costs for the oxygen plant are excluded because no cost data for that type of plant was available.

Infrastructure costs associated with bringing utilities to the Tosco II site are accounted for in various ways. Costs associated with (1) bringing in an electrical substation ($6.3 million), (2) establishing the electrical line, switching gear, and tap ($2.8 million), (3) bringing in the natural gas line ($6.9 million), and (4) establishing the metering hub ($1 million) have been obtained from Sage Geotech [24]. The costs of the water pipeline ($13.2 million) and the water reservoir ($37.6 million) have been estimated using standard construction and excavation cost estimation methods [22,25]. Warehousing costs of chemicals are accounted for in the percentage (10%) of the C_{TBM} used for service facilities [8]. Infrastructure costs for the Paraho Direct retort are the same with the exception of the following: (1) the electrical substation cost is $37.5 million, (2) the water pipeline cost is $8.4 million, and (3) the water reservoir cost is $19.1 million.

Costs given here are for the Tosco II air-fired case. For oxy-firing, the cost of the electrical substation increases to $15.4 million and the water reservoir to $37.8 million.

Bare module cost is the cost of a piece of equipment, transportation of the equipment to the plant site and installation including foundations, piping and control systems. C_{TBM} is the sum of all bare module costs for equipment and process units.

6.1.14 Labor Utilization

Skilled and maintenance labor as well as management are required for all aspects of ex situ oil shale production. Skilled labor and management requirements are considered in this section (see Table 6-4). The number of people employed to perform maintenance labor is excluded from the totals in Table 6-4. Instead, the costs of maintenance labor are assumed to be covered by the yearly maintenance cost (5% of C_{TDC}).

The number of employees on a per shift basis is determined for each unit operation of the entire production process as listed in Table 6-4. Assuming that five shifts per week are used for 24/7 operation, the total number of employees for this scenario is 1,375; that number increases to 1,410 for the scenario variation with oxy-firing.

Here it is assumed that with illnesses, vacations, holidays, etc., the number of 40-hour shifts required per week is rounded up from 4.2 (168 hours/ (40 hours per shift)) to 5.

Table 6-4. Labor requirements for ex situ oil shale extraction (per shift).

Process	Operators	Lab & Engineering	Management
Underground Mine	150	---	8
Grinder & Retort	54	2	3
Fractionator	2	2	1
Hydrotreater	18	2	1
H_2 Plant	6	2	1
Sour Water Stripper	4	2	1
Amine Treatment Unit	4	2	1
Sulfur Recovery Unit	6	2	1
Total	**244**	**14**	**17**
- - - - - - - - - - - - - - - - - - - -	*Oxy-Fired Only*	- - - - - - - - - - - - - - - - - - - -	
CO_2 Compressor	4	2	1
Total	**248**	**16**	**18**

These labor requirements are for the startup and production phases of the project and do not include labor required for construction of the various unit operations.

The sources used to determine labor requirements for both the Tosco II and Paraho Direct processes are the same, so labor requirements are identical. Mining labor requirements are extrapolated based on data obtained from InfoMine [26] for underground mines producing on the order of 1,200 to 14,000 TPD (1,090 to 12,700 MTPD) of ore. Labor requirements for all other unit operations are estimated following the approach given by Seider et al. [8]. However, due to the scale of the mining operation and the uncertainty associated with labor estimating methods in Seider et al. [8], actual labor requirements could be quite different from those predicted here.

Seider et al. [8] is a standard reference for the chemical industry, but it is not specific to oil processing/ refining and it does not claim expertise at making labor estimates.

6.2 Environmental Aspects of Ex Situ Oil Shale Scenario

The Tosco II process requires that 87,800 tons TPD (79,700 MTPD) of ore be mined. For the Paraho Direct process, 95,450 TPD (86,600 MTPD) of ore are mined.

This profitability analysis does not include the cost of externalities associated with visual impairment, effects on ground and surface water quality, the reallocation of a large land surface area for industrial use, or the treatment and storage costs for waste streams other than spent shale (e.g. waste oil, coke residue, spent catalysts, etc.), all of which are very small compared to the spent shale. This analysis does account for the costs of some air pollution control, the treatment and long-term storage of spent shale, carbon management, and water management as described below.

6.2.1 Air Pollution Control

As outlined in Sections 6.1.9 and 6.1.10 above, this scenario includes the costs of removing H_2S from the various sour gas streams generated by the upgrading of shale oil. Capital and operating expenses for removing NH_3 are assumed to be offset by the sale of ammonium sulfate; see Section 6.1.8. All other capital costs for air pollution control equipment for this scenario could be computed based on flowrate estimates of the waste air streams, but similar information is not available for the other scenarios. In addition, operating costs are extremely difficult to estimate. Hence, these additional costs for air pollution control are assumed to be covered by the scenario's contingency cost, which is $565.5 million. Given its low cost impact, this assumption is not seen as a serious omission for the purposes of this analysis.

Capital costs for air pollution control equipment not included in Section 6.1 are expected to be in the $100,000–$900,000 range.

6.2.2 Treatment and Storage of Spent Shale

Spent shale management is an important component of this ex situ oil shale scenario given the large volume of material that must be disposed of. The spent shale contains all the mineral matter that was in the raw shale plus a few percent of unrecoverable kerogen or its non-volatile organic derivatives. For this scenario, approximately 91,700 TPD (83,200 MTPD) of damp (15.4 wt% water) spent shale will be produced from the Tosco II process, which over the 20-year life of the project will equal a total of approximately 604 million tons (548 million metric tons) or 13,430 million cubic feet (380 million cubic meters). The Paraho Direct process produces approximately 79,000 TPD of spent shale, which has a water content near zero as there is no shale moisturizing step. Additional water is used for disposal and compaction in both processes, resulting in an average moisture content of the disposed spent shale of 17.3 wt% for the Tosco II process and 5.0 wt% for the Paraho Direct process.

A 1981 handbook [27] lists 88–98 pounds per cubic foot (lb/ft^3), 1,410–1,570 kilograms per cubic meter (kg/m^3), as the range of densities for compacted spent shale from the Paraho process and 91.8–101.2 lb/ft^3 (1,470–1,621 kg/m^3) from the Tosco II process. For computing spent shale volumes in this report, a value of 90 lb/ft^3 (1,442 kg/m^3) is used.

The spent shale will be disposed of on 4,000 acres (1,600 hectares) of the tract surface. The surface topography of the Uinta Basin contains both valleys and plateaus which on average will require a disposal pile height of 200 feet (61 meters) above the surrounding terrain. The disposal area site location must consider the distance from the retorting plant as well as the location of dams in filled valleys necessary to contain surface precipitation and collection of water which may filter through the pile. Prior to initial processed shale placement, usable soil and overburden materials will be removed and stockpiled for reuse in reclamation.

Moist processed shale emerges from the Tosco II retorting operation at a temperature of about 200°F (93°C). The moisture content is raised to 15.4% on a dry weight basis as it leaves the plant moisturizer; additional water is needed for disposal and compaction. The processed shale is placed on a covered conveyor. At the end of the conveyor, a surge bin and truck loading facility transfer the processed shale directly into 150-ton bottom dump trucks for transport to the disposal area.

Spent shale exits the Paraho Direct retort at a temperature of 295°F (146°C). It is then transported by conveyor either directly to the disposal site or to bottom-dumping trucks, which then transport the spent shale to the disposal site [4].

The material will be deposited on the surface in approximately 18-inch (0.46-meter) layers, moisturized and compacted. This procedure will continue until the layer is 10 feet (3 meters) thick and covers all ground cleared and stripped. The next 70% of the pile will be deposited in 50 to 120 feet high (15–36.5 meters), uncompacted lifts. Fugitive dust will be controlled by water trucks. Bulldozers operating on top of each lift will be used to level the surface and provide minimal compaction. The face of the pile will have an overall slope of 4:1 with benches at uniform intervals. The final layer of processed shale covering all exposed material will be 5–10 feet (1.5–5 meters) thick, compacted and moisturized.

To achieve optimum compaction in the 18-inch layer using spent shale from the Paraho Direct retort, the moisture content should average 17 wt%.

Lifts may be higher in localized areas over gulches.

Erosion of embankment slopes and infiltration of storm water into and through the deposited processed shale will be minimized. The horizontal benches will have a 10% slope toward the embankment and will lead to downslope collector drains which will divert runoff to the bottom of the embankment slope. A low dam and settling ponds at the foot of the embankment slope will be constructed to catch solids.

For reclamation, the processed shale disposal embankment will be graded, shaped, contoured and compacted. Organic material and fertilizer will then be worked into the surface of the embankment to a depth of six to eight inches (0.15–0.20 meters). Next, a six-inch (0.15-meter) cover of native soil will be spread over the surface of the embankment and an above ground sprinkler system will be installed. Lastly, the area will be seeded with native vegetation determined to be best for revegetating processed shale and mulched with appropriate cover.

The capital and operating costs for spent shale disposal and reclamation used in this scenario were obtained from Mr. Robert Loucks, an oil shale industry consultant with extensive experience in performing capital cost estimates for oil shale projects in Colorado over the period from the 1970's and 1980's to the present. Mr. Loucks based his numbers on similar industry projects for which he had data. Capital costs for spent shale disposal and reclamation are assumed to be covered by the total combined capital cost for mining, crushing, and solids disposal scaled from Weiss et al. [2]. Operating costs for the same were obtained from Mr. Robert Loucks, a Colorado-based oil shale industry consultant, who based his numbers on similar industry projects for which he had data.

6.2.3 Carbon Management

Given the uncertainty of the regulatory climate with respect to carbon, a careful accounting of CO_2 production, possible mitigation methods, and potential costs are an essential part of this scenario. To accomplish these objectives, two different combustion systems are considered to supply heat for the various unit operations.

In the conventional system, natural gas is combusted with air and the resulting combustion gases are sent to a stack. For this system (e.g. no CO_2 capture), two cases are considered in the profitability analysis that follows: (1) no tax on CO_2 and (2) a $25 per ton tax on CO_2.

In the oxy-combustion system, natural gas is combusted with a mixture of O_2 and RFG consisting primarily of CO_2 and H_2O. Using a ProMax simulation, the product gases are then cooled to cryogenic conditions in a series of heat exchangers such that condensible gases (H_2O, H_2S and NH_3) can be removed; see Figure 6.11. The nearly pure CO_2 stream that remains after cryogenic treatment is compressed to pipeline conditions. Equipment sizes and operating requirements for the CO_2 compression system are calculated using ProMax.

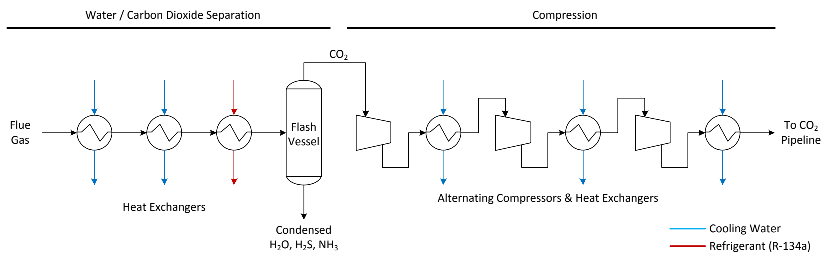

Figure 6.11: Process flow diagram for CO_2 compression system.

The costs of the combustion and CO_2 compression systems are calculated as follows. For the combustion system, all of the equipment is costed in ProMax and then rolled into the cost reported for the hydrotreater. For CO_2 compression, Castro [11] costed 25 CO_2 compressor systems at various scales (400,000–30,000,000 tons per year of CO_2) using Promax. A regression fit to this data is used to interpolate capital and utility requirements (e.g. costs) for the CO_2 compression system. The O_2 required for oxy-firing is purchased from a supplier at the price per ton listed in Table 5-7.

This scale range is equivalent to 363,000–27,000,000 metric tons per year.

Suppliers of O_2 include Praxair and Air Products.

These costs are offset by the sale of CO_2 to a pipeline company for EOR, which is currently $25 per ton at pipeline conditions [28]. By the time oil shale is developed in the Uinta Basin, conventional oil production in the area may need a source of CO_2 for EOR, making this pipeline a short one. The costs of a CO_2 pipeline are assumed to be the responsibility of the purchaser and are not included in the present analysis. Additional details about the CO_2 compression and cleanup plant can be found in Castro [11].

For both the air- and oxy-fired cases, GHGs (including CO_2, CH_4, and N_2O) are produced from: mining and transport of the shale; heating and electricity associated with the hydrogen plant, the hydrotreater, and the surface retort; product transport to the refinery; and the air separation unit that produces O_2 for the oxy-fired case. For the air-fired Tosco II process, total CO_2e emissions from these sources are 4.497 million tons (4.080 million metric tons) per year. For the oxy-combustion case, 3.845 million tons (3.488 million metric tons) per year of pipelineable-quality CO_2 are produced and 1.603 million tons (1.454 million metric tons) CO_2e are emitted. These totals neglect the CO_2 associated with construction of the facilities, refrigeration, water treatment, and decomposition of carbonates in the oil shale. For the air-fired Paraho Direct retort, carbonate decomposition cannot be neglected due to the 1200°F (649°C) operating temperature of the retort. Total estimated CO_2e emissions from the Paraho Direct production process with carbonate decomposition included are 6.872 million tons (6.234 million metric tons) per year.

Carbonate decomposition in the Tosco II retort is expected to be small. The dominant carbonate minerals in the Uinta Basin oil shale zones of interest are dolomite and calcite. Decomposition of these minerals occurs at 1112°F (600°C) and above while the operating temperature of the retort is 900°F (480°C).

A more detailed analysis of CO_2 emissions from an ex situ oil shale production process that includes refining is found in Brandt [29]. Brandt reports a range of 62–75 g CO_2e/MJ for shale oil produced by the ATP retorting process. For this scenario employing a Tosco II retort, CO_2 emissions are estimated to be 53 g CO_2e/MJ gasoline (air-fired) and 26 g CO_2 e/MJ gasoline (oxy-fired) [30]. For the Paraho Direct process (air-fired), CO_2 emissions are estimated to be 77 g CO_2e/MJ gasoline (air-fired) [30]. These values are obtained using CO_2 emissions computed as described in this section and adding emissions from refining.

The estimate for oxy-firing does not include the pipelineable-quality CO_2 that is produced.

6.2.4 Water Management

Since no commercial-scale ex situ oil shale production facilities are currently operating in the U.S., estimating process water usage is a challenge as noted in Section 4.2.1 and reported by the U.S. GAO [31]. In general, each part of the oil shale conversion process either generates water, consumes water, or is water neutral (i.e. it recycles the water moving through it). These three possibilities are illustrated in the generic water balance shown in Figure 6.12.

"Water in" or makeup water is the water needed to replace the water lost in the process due to hydration of spent shale, evaporation, dust control, etc.

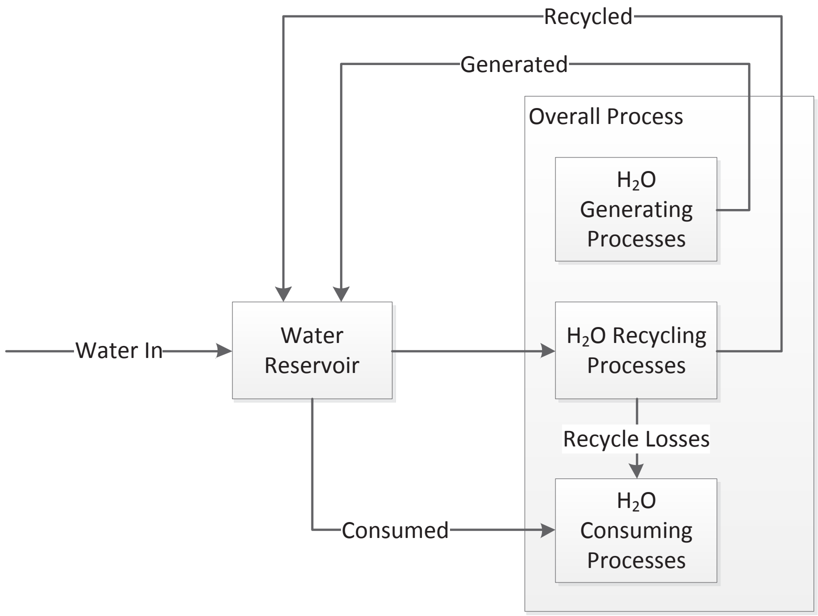

Figure 6.12: Generic water balance diagram. Each part of the oil shale production process either generates, consumes, or recycles water.

6.2.4.1 Itemized Water Balance

Itemized water balances for the air- and oxy-fired ex situ oil shale scenarios (Tosco II and Paraho) are shown in Table 6-5 on both a per barrel and annual water usage basis. Total required makeup water for the two Tosco II scenarios is very similar: 14,773 acre-feet (18.22 million cubic meters) per year for the air-fired case and 14,876 acre-feet (18.35 million cubic meters) per year for the oxy-fired case. In contrast, the total required makeup water for the air-fired Paraho Direct process is 7,049 acre-feet (8.69 million cubic meters).

An acre-foot is the volume contained by one acre of surface area at a depth of one foot. One acre-foot of water is 325,850 gallons (1233 cubic meters).

Table 6-5. Itemized water balance for ex situ oil shale production; data obtained from various sources [10,17,30,31] and from Promax simulations.

bbl/bbl of oil = barrel per barrel of oil

Category	Item	Water (bbl / bbl of oil)			Water (acre-ft/yr)		
		Tosco II Air-Fired	Tosco II Oxy-Fired	Paraho Air-Fired	Tosco II Air-Fired	Tosco II Oxy-Fired	Paraho Air-Fired
Recycled	Cooling Water						
	Hydrotreater	0.10	0.10	0.10	244	246	244
	H_2 Plant	2.32	2.32	2.32	5,460	5,459	5,460
	CO_2 Compressor	-	34.34	-	-	80,783	-
	Sulfur Recovery Unit	0.10	0.10	0.10	246	245	246
	Boiler Feed Water						
	Sulfur Recovery Unit	0.02	0.02	0.02	37	37	37
	Retort	Unknown					
	Steam	1.46	1.46	1.24	3,425	3,425	2,922
	Subtotal	**4.00**	**38.34**	**3.79**	**9,411**	**90,196**	**8,909**
Consumed	H_2 Plant	0.83	0.83	0.83	1,942	1,942	1,942
	Mining and Crushing [a]	0.59	0.59	0.46	1,390	1,390	1,075
	Retort						
	Cooling Tower Makeup	2.18	2.18	1.87	5,134	5,134	4,403
	Retorting	1.06	1.06		2,505	2,505	
	Other [b]	0.69	0.69	0.31	1,626	1,626	740
	Spent Shale [c]	2.20	2.20	0.67	5,182	5,182	1,582
	Upgrading						
	Cooling Tower Makeup	0.19	1.22	0.14	458	2,881	334
	Steam Recycle Losses	0.04	0.04	0.04	103	103	88
	Subtotal	**7.80**	**8.83**	**4.32**	**18,340**	**20,763**	**10,165**
Generated	CO_2 Compressor	-	0.99	-	-	2,320	-
	Retort						
	Cooling Tower Blowdown [d]	0.70	0.70	0.80	1,650	1,650	1,889
	Retort Condensate [e]	0.47	0.47	0.26	1,106	1,106	607
	Other [f]	0.35	0.35	0.26	812	812	620
	Subtotal	**1.52**	**2.50**	**1.32**	**3,567**	**5,887**	**3,116**
Water In		**6.28**	**6.32**	**3.00**	**14,773**	**14,876**	**7,049**

[a] *Water requirements for mining and crushing are taken directly from the Office of Technology Assessment (OTA) report [32].*

[b] *"Retort - Other" includes other boiler makeup water, steam and treatment loss, service and fire water, and potable and sanitary water [32].*

[c] *"Spent Shale" includes water for shale moisturizing (Tosco II retort only), disposal and compaction, and reclamation.*

[d] *"Cooling Tower Blowdown" refers to water "that is drained from cooling equipment to remove mineral build-up" [33].*

[e] *"Retort - Retort Condensate" includes gas and upgrading condensates.*

[f] *"Retort - Other" includes boiler and treatment waste, service water effluent, and potable and sanitary effluent.*

The process units listed in the "Recycled" category of Table 6-5 require water treated to either cooling or boiler quality for normal operation. However, this water is not consumed but is used as a heat transfer medium. Recycled water leaving these process units is sent to cooling towers where it is assumed that 3 wt% of the water is lost to evaporation. Water flow rates for these units are determined from process flowsheet calculations in ProMax (hydrotreater and CO_2 compressor) or scaled from literature values (Maples [10] for sulfur recovery unit and Fleshman [17] for the hydrogen plant). Recycled water requirements for the retort are unknown. The most detailed tabulation of water requirements for both Tosco II and Paraho Direct retorts is given in a water consumed and water generated format [32].

The equivalent makeup water flow rate in cubic feet per second (CFS) is 20.41 CFS (0.5778 cubic meters per second or CMS) for the Tosco II air-fired case, 20.55 CFS (0.5819 CMS) for the Tosco II oxy-fired case, and 9.74 CFS (0.276 CMS) for the Paraho Direct air-fired case.

Several process units consume water. Water is consumed by the chemical conversion of steam and CH_4 to H_2 and CO_2 in the hydrogen plant. The water required for this conversion is scaled from data in Fleshman [17]. Water usage for spent shale disposal, including moisturizing spent shale (Tosco II process only), disposal and compaction, and revegetation, is obtained from the OTA report [32]. The "Upgrading - Cooling tower makeup" item is the sum of all of the cooling tower evaporation losses from recycled water streams in the hydrotreater, hydrogen plant, sulfur recovery unit, and CO_2 compressor. Steam recycle losses for upgrading are based on an estimate of 3% water loss by volume for steam generation in a closed cycle loop [34]. All other line items in the "Consumed" category are scaled from data in the OTA report [32].

In a water balance for a new SAGD plant in Alberta, Connacher estimates steam recycle losses of 3% by volume; see Table B.6.1.1 in the Connacher report [34].

Other small water uses, including water used for various scrubbers, are assumed to be negligible and are not included in the present analysis. For all air-fired scenarios, the water contained in the combustion gases that are sent to the stack is not included as a water loss. Finally, water required to initially charge the entire system is not included in the water balance in Table 6-5.

The largest water use is for replacing water that is evaporated in the cooling towers to cool the recirculated process water flow ("Cooling Tower Makeup" in Table 6-5). This water recycling loss occurs in both the retort and the upgrader. Spent shale moisturizing, a large water use for the Tosco II process, is not required in the Paraho Direct process, resulting in reduced water consumption for Paraho Direct spent shale disposal. The source of water for spent shale disposal is waste water streams from various production and upgrading process units.

Water is also used in the mine for dust control and reclamation and in the retort for wet scrubbers (used for cleaning up flue gases) and for steam generation. Water in the form of steam is used in the hydrogen plant as a reactant; cooling water and process water are also used. The hydrotreater uses both steam and cooling water. The CO_2 compression plant uses cooling water for the inter-stage coolers.

Steam purchased from the off-site utility is used to supplement steam generation in the retort.

Water in the "Generated" category is produced during the heating of shale, the condensation of oxy-fired flue gases, and the treatment of effluents. Water produced from oil shale retorting is computed from the water content of the raw shale. Condensed water from the CO_2 compressor system in the oxy-fired scenario is calculated based on the mass flow rate of CO_2 and assumptions of complete combustion and recovery of all water in the flue gases. All other line items in this category are scaled from OTA report [32].

6.2.4.2 Water Availability and Infrastructure

The main source of water in this area of the Uinta Basin is the White River. Monthly average flow rates for the White River are shown below in Figure 6.13 based on data from USGS [34]. The average flow rate in the river is 692 CFS (19.6 CMS), with the highest monthly flow recorded in June 2011 at 4,363 CFS (123.5 CMS) and the lowest monthly flow recorded in July 2002 at 73.1 CFS (2.07 CMS). Hence, the White River flow is larger than the required Tosco II process makeup water flow by a factor of 34 on average and by a factor of 3.6 during the river's lowest recorded flow. For the Paraho Direct process, the river flow is higher by a factor of 70 on average and by a factor of eight at the lowest recorded flow.

The White River is located a short distance from the mine site. The White River is a tributary of the Green River.

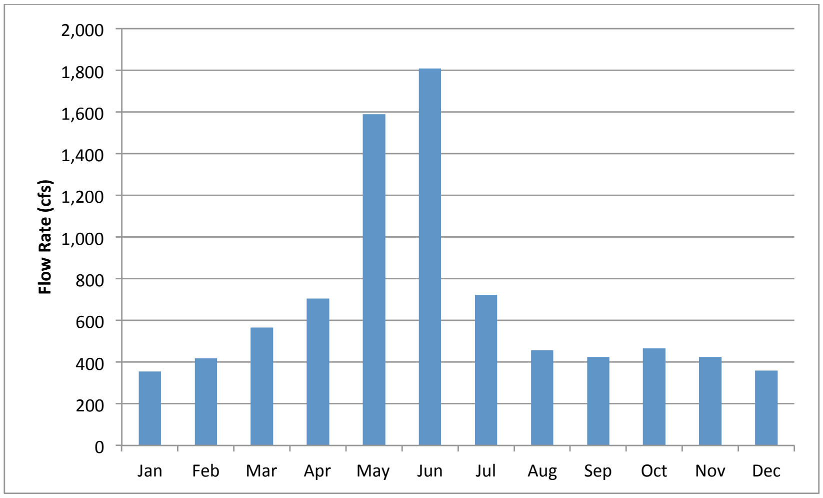

Figure 6.13: Average historical discharge from White River by month [35].

The extraction and upgrading processes require water on a daily basis (supplied from an on-site reservoir) plus a one-time filling of tanks for start-up. In this region, water rights must be owned by the development project or the water must be purchased from other users at a rate of $50 per acre-foot per year [36]. If water must be purchased, the owners of agricultural water rights are the principal rights holders in this area. Hence, water use for oil shale production will reduce the water available for agriculture.

Assuming that water rights are available for purchase, the effect on profitability of owning water rights versus purchasing water rights is negligible; water management costs are less than 1% of the overall cost of the project and the cost of purchasing makeup water represents 9% of the water management costs. If the project owns water rights, costs for water management are associated with building the reservoir and treating the water to the quality required for process cooling water and boiler feed water.

The on-site reservoir will be filled by diversion of or pumping from the White River. A short water pipeline from the White River to the plant site is needed to fill the water storage reservoir for daily use. The cost of building this pipeline, assumed to run in a straight line between the site and the river, is included in the present analysis.

Historical periods of drought are defined as the length of time between rainstorms over the basin.

The size of the reservoir is determined by the duration of a prolonged drought in the area as water may either be unavailable for purchase or the price may be very high. To determine a rough estimate of reservoir size, historical periods of drought were studied. Based on this analysis, the worst-case scenario for water storage capacity was 90 days or the duration of the summer. Based on total water utilization for Tosco II and Paraho Direct processes (see Table 6-5) and the need for a 90-day supply of water, the estimated reservoir sizes are: 3,643 acre-feet (3.99 million cubic meters) for the Tosco II air-fired case, 3,668 acre-feet (4.01 million cubic meters) for the Tosco II oxy-fired case and 1,738 acre-feet (2.14 million cubic meters) for the Paraho Direct air-fired case. Costs for the reservoirs are determined using construction excavation costs that are applicable in the Uinta Basin. The cost of a lined water reservoir is not trivial: $37.6 million for the Tosco II air-fired operation, $37.8 million for the Tosco II oxy-fired operation, and $19.1 million for the Paraho Direct air-fired operation.

6.3 Profitability Analysis of Ex Situ Oil Shale Production

All dollar values given in this section are reported as 2012 US$ unless otherwise noted. An inflation rate of 1.8% is used to adjust dollar values from other reports to 2012 US$, except for instances where more specific inflation indices are available (such as CEPCI for chemical processing equipment, ENR for construction costs, PPI for mining, drilling, and chemicals, etc.).

The hurdle rate is the opportunity cost of capital or the rate of return on investments with similar risk/reward profiles.

This ex situ oil shale production profitability analysis, performed for the Tosco II air- and oxy-fired cases and the Paraho Direct air-fired case, includes four parts: an estimation of capital costs associated with extraction, upgrading, and transportation to market (e.g. a refinery), a "base case" supply price profitability analysis as a function of hurdle rate, an NPV profitability analysis based on EIA oil price forecasts and defined hurdle rates, and a supply price sensitivity analysis that, for a range of hurdle rates, examines the effects on profitability of varying model inputs and parameters from the "base case" values. Raw shale oil production costs at the mine site (excluding upgrading and transportation costs) are also included for comparison. All costs and profitability measures are reported in terms of real dollars. Both the Supply Price Method and the NPV Method consider all the costs associated with SCO production as described in Sections 5.4 and 6.1.

Table 6-6 lists the key assumptions for the base ex situ oil shale cases using air-fired and oxy-fired combustion for plant heating. For the Tosco II and Paraho Direct air-fired production scenarios, all of the process heat is supplied by air-fired combustion of purchased natural gas supplemented by produced gas streams from three sources: (1) the distillation column in the retort section of the plant, (2) the hydrogen plant, and (3) the hydrotreater. For the Tosco II oxy-fired production scenario, all of the process heat is supplied by oxy-fired combustion of natural gas supplemented by the same streams.

Table 6-6. Ex situ oil shale scenario base case assumptions.

Category	Input/assumption
Air- & oxy-fired	
Average oil shale grade	25 GPT
Kerogen recovery	Tosco II retort - 90% of Fischer assay Paraho Direct retort 92% of Fischer assay Hydrotreater - 98.1 wt% of shale oil feed
Hydrogen consumption	2000 SCF/bbl
Utility pricing	Fixed prices from Table 5-7
Hurdle Rate	0–12%
Taxes and Royalties	Federal: 35% of Taxable Income State: 5% of Taxable Income Property: 1% of Total Permanent Investment Severance[a]: 3–5% of Adjusted Wellhead Price Conservation Fee: 0.2% of Adjusted Wellhead Price Oil Royalty[a]: 5–12.5% of Oil Sales
Product	WTI-quality SCO
Air-fired	
CO_2 tax	None
Revenue	Oil, sulfur, and steam
Oxy-fired	
CO_2 sales	$25/ton
Revenue	Oil, CO_2, sulfur, and steam

[a] *See Section 5.4.3 for scenario accounting details related to tax and royalty rates.*

Table 6-7 lists the major outputs from and inputs to ex situ production of SCO from oil shale on a per barrel basis. The production of CO_2 is greater for the Paraho Direct process than for the Tosco II process because the high temperature in the retort leads to formation of CO_2 from carbonate decomposition; CO_2 emissions from carbonate decomposition in the the Tosco II retort are assumed to be negligible. Also, while the per barrel production of CO_2 for the Tosco II air-fired and oxy-fired processes is similar, the CO_2 from the oxy-fired scenario has been captured, is of pipeline-quality, and can be sold while the CO_2 from the air-fired scenario is dilute and is emitted into the atmosphere from a smokestack.

Table 6-7. Major process outputs and inputs on a per barrel basis.

Category	Item	Tosco II Air-Fired	Tosco II Oxy-Fired	Paraho Air-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	20.94	20.94	20.94	lb
	CO_2 [a]				
	Emitted to Atmosphere	544	191	833	lb
	Sold to Pipeline	-	421	-	lb
	Spent Shale	41.69	41.69	42.02	ft^3
	Steam (600 psig, 700°F)	396	396	396	lb
	Sulfur	1.96	1.96	1.96	lb
Inputs	Catalyst	0.02	0.02	0.02	lb
	Electricity	14.31	35.96	88.77	kWh
	Fuel [b]				
	Purchased	1.19	1.16	1.93	MMBtu
	Total	3.84	3.80	3.01	MMBtu
	Makeup Water	6.28	6.32	3.00	bbl
	O_2	-	396	-	lb
	Refrigerant	2.72	2.72	2.72	MJ
	Steam				
	50 psig	433	433	250	lb
	450 psig	77	77	184	lb

[a] The per barrel CO_2 output is CO_2e. These emissions do not include those associated with facilities construction, refrigeration, and water treatment. The CO_2e for the Tosco II processes does not include emissions from carbonate decomposition.
[b] The fuel input refers to natural gas only. The difference between the purchased and total fuel is the fuel credit.

Comparing electricity requirements, the oxy-fired Tosco II process requires more than double the electrical input of the air-fired process. This difference is due to the electrical demand of the CO_2 compression system. The Paraho Direct process requires six times the electricity of the Tosco II air-fired process because the retort uses large volumes of combustion air and electrical pumps are needed to blow the air to where it is needed.

Even though the total fuel demand for the Paraho Direct process is lower than that for the Tosco II air-fired process, the lower quality gas produced from the Paraho Direct process requires that more natural gas be purchased to run the hydrotreater than for the Tosco II process. In other words, the Tosco II process uses more fuel but gets a higher fuel credit offset.

The total heating value of the produced gas from the Tosco II process is assumed to be 48.2 MMBtu per year while that of produced gas from the Paraho Direct process is 19.7 MMBtu per year.

Differences in per barrel water requirements were discussed in Section 6.2.4. The larger steam input for the Tosco II process is driven by the technology used to heat the crushed shale in the retort. In the Tosco II retort, steam is used as a heat transfer medium to heat ceramic balls in a steam superheater. The ceramic balls are then used to heat the crushed shale.

6.3.1 Capital Costs for Ex Situ Oil Shale Extraction

The total capital investment for the complete Tosco II air-fired plant is \$5.941 billion; that of the Tosco II oxy-fired plant is \$6.192 billion. Capital costs for the Paraho Direct air-fired plant are almost 20% lower; the total capital investment is \$4.789 billion. A breakdown of all capital costs is shown in Table 6-8; definitions for all cost categories can be found in Section 5.3.4. For the Tosco II process with an air-fired heating system, the largest capital costs are for the retort (21%), hydrotreater (14%), and mine (11%). These percentages are only slightly changed for the Tosco II oxy-fired case. For the air-fired Paraho Direct process, the simpler retort design is reflected in the lower retort cost compared with Tosco II; the largest capital costs are for the hydrotreater (18%), mine (16%), and then retort (11%).

Table 6-8. Capital cost breakdown by unit for the base case ex situ oil shale scenario in millions of 2012 US\$.

Category	Item	Tosco II Air-fired	Tosco II Oxy-fired	Paraho Air-fired
Total Bare Module Investment - C_{TBM}	Underground Mine	\$ 659.7	\$ 659.7	\$ 773.5
	Oil Shale Retort	\$ 1,230.1	\$ 1,230.1	\$ 533.5
	Fractionator	\$ 44.2	\$ 44.2	\$ 44.2
	Hydrotreater	\$ 846.4	\$ 852.4	\$ 846.4
	H_2 Plant	\$ 88.7	\$ 88.7	\$ 88.7
	Sour Water Stripper	\$ 65.0	\$ 65.0	\$ 9.5
	Amine Treatment Unit	\$ 2.1	\$ 2.1	\$ 2.1
	Sulfur Recovery Unit	\$ 6.0	\$ 6.0	\$ 6.0
	CO_2 Compressor	\$ -	\$ 74.4	\$ -
	C_{TBM} Subtotal	**\$ 2,942.2**	**\$ 3,022.6**	**\$ 2,304.0**
Total Direct Permanent Investment - C_{DPI}	Site Preparation	\$ 294.2	\$ 302.3	\$ 230.4
	Service Facilities	\$ 294.2	\$ 302.3	\$ 230.4
	Oil Pipeline	\$ 114.6	\$ 114.6	\$ 114.6
	Water Pipeline	\$ 12.3	\$ 12.3	\$ 8.4
	Water Reservoir	\$ 33.7	\$ 33.9	\$ 19.1
	Allocated Costs for Utility Plants	\$ 78.7	\$ 107.0	\$ 94.4
	C_{DPI} Subtotal	**\$ 3,769.9**	**\$ 3,894.9**	**\$ 3,001.2**
Total Depreciable Capital - C_{TDC}	Contingency	\$ 565.5	\$ 584.2	\$ 450.2
	C_{TDC} Subtotal	**\$ 4,335.3**	**\$ 4,479.1**	**\$ 3,451.4**
Total Permanent Investment - C_{TPI}	Land	\$ 86.7	\$ 89.6	\$ 69.0
	Permitting	\$ 31.8	\$ 31.8	\$ 31.8
	Royalties for Intellectual Property	\$ 86.7	\$ 89.6	\$ 69.0
	Startup	\$ 433.5	\$ 447.9	\$ 345.1
	Investment Site Factor	1.15	1.15	1.15
	C_{TPI} Subtotal - US Midwest	**\$ 5,720.2**	**\$ 5,908.6**	**\$ 4,561.3**
Total Capital Investment - C_{TCI}	Working Capital	\$ 220.6	\$ 283.4	\$ 227.9
	Total (\$)	**\$ 5,940.8**	**\$ 6,192.0**	**\$ 4,789.2**

In the Canadian oil sands industry, capital costs are frequently reported as CPFB. This ratio is computed by taking C_{TCI} from Table 6-8 and dividing by the production barrels per day; see Equation (5.5). This ex situ oil shale extraction scenario has a CPFB of \$118,815 for the Tosco II air-fired case, \$123,840 for the Tosco II oxy-fired case, and \$95,785 for the Paraho Direct air-fired case.

The capital costs for this scenario were reviewed by Mr. Robert Loucks, an oil shale industry consultant with extensive experience in performing capital cost estimates for oil shale projects in Colorado since the 1970's. For his review, Mr. Loucks took 12–15 estimates that were performed in the 1980's and scaled them up to 2012 US$ in broad cost categories using the ENR cost index. As shown in Table 6-9, the total depreciable capital based on Mr. Loucks' aggregated data from 12–15 projects was $4.502 billion (CPFB of $90,044, excluding capital costs for C_{TPI} and C_{WC}) compared to the present estimate of $4.335 billion for the Tosco II process and $3.451 billion for the Paraho Direct process (CPFB of $86,707 and $69,028, respectively, excluding capital costs for C_{TPI} and C_{WC}). Table 6-9 also compares the capital cost breakdown in this report with that received from Mr. Loucks.

Not all cost categories were included in all the estimates.

Because of the way costs were aggregated by Mr. Loucks, it is not possible to provide a direct comparison for all cost categories.

Table 6-9. Comparison of capital cost breakdown by unit for base case ex situ oil shale scenario in millions of 2012 US$ as reported by Mr. Loucks and as computed in this report.

These estimates are only for the total depreciable capital (C_{TDC}), not the total capital investment (C_{TCI}). Also, due to the different cost estimating methodologies, not all capital cost line items are directly comparable. Mr. Louck's values are adjusted to 2012 US$ by the ENR index.

Category	Item	Loucks	Tosco II Air-fired	Paraho Air-fired
Total Bare Module Investment - C_{TBM}	Upgrader [a]	$ 352.2	$ 1,052.4	$ 996.9
	Underground Mine	$ 749.6	$ 659.7	$ 773.5
	Oil Shale Retort	$ 1,380.4	$ 1,230.1	$ 533.5
	C_{TBM} Subtotal	**$ 2,482.3**	**$ 2,942.2**	**$ 2,304.0**
Total Direct Permanent Investment - C_{DPI}	Site Preparation		$ 294.2	$ 230.4
	Service Facilities	$ 474.2	$ 294.2	$ 230.4
	Oil & Water Pipeline	$ 231.3	$ 126.9	$ 123.0
	Water Reservoir		$ 33.7	$ 19.1
	Allocated Costs for Utility Plants	$ 193.5	$ 78.7	$ 94.4
	Associated Project Cost	$ 434.2		
	C_{DPI} Subtotal	**$ 3,815.4**	**$ 3,769.9**	**$ 3,001.2**
Total Depreciable Capital - C_{TDC}	Contingency	$ 686.8	$ 565.5	$ 450.2
	C_{TDC} Subtotal	**$ 4,502.2**	**$ 4,335.3**	**$ 3,451.4**

[a] "Upgrader" includes the fractionator, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.

Although the C_{TDC} estimates from the present work and Mr. Louck's analysis are in the same range, there are significant differences on individual line items. The greatest discrepancy occurs in estimating the cost for upgrading; the present methodology results in a capital cost that exceeds by a factor of three the cost reported by Mr. Loucks. However, a recent CERI report on the cost of actual standalone upgrading projects for Canadian oil sands has found an average CPFB of $50,534 [37], which is approximately 15% higher than this report's CFPB estimate of $43,185 for the Tosco II oil shale upgrader and 20% higher than the CPFB of $40,698 for the Paraho Direct oil shale upgrader. While there are differences between oil sands and oil shale upgraders (differing H_2 requirements, coking unit included in oil sands upgrading, etc.), the oil sands CPFB is obtained from current industry data and thus provides a point of comparison that is not speculative.

CERI reports numbers in C$. To convert to US$, an exchange rate of 1:1 is assumed. Numbers have been adjusted to 2012 US$ using the CEPCI inflation index.

The CPFB estimate for the Tosco II and Paraho Direct upgraders includes all capital costs except for the mine, the retort, and the oil pipeline.

The RAND Corporation published a report estimating the total capital cost for a 50,000 BPD surface retort oil shale development at $6.2–$8.6 billion for a CPFB of $123,000–$173,000 [38]. This cost includes mining, retorting, upgrading, and transportation. The CPFB reported by Red Leaf is $29,461 for a 9,500 BPD operation and includes capital costs for mining, retorting, and transportation; the retort product is assumed to be refinery-ready with

All CPFB values given here have been adjusted to 2012 US$ using the CEPCI index.

no upgrading required [39]. Analysis of the primary drivers of these cost differences is not possible due to the lack of publicly available data.

As a final point of comparison, almost three decades ago Wells et al. [40] developed a methodology for performing economic evaluations of SCO production from oil shale and oil sands resources in Utah. As with the present report, they employed detailed capital cost information from the 1979 STRAAM report [7] in their analysis. In evaluating a 10,000 BPD ex situ oil shale development scenario, the capital costs for processing (retorting, upgrading, and associated costs) accounted for 60% of the total cost with the remaining 40% for mining. In terms of C_{TDC}, the crushing/retorting cost was 17.9% and the upgrading cost was 17.6%. In this report (see Tables 6-8 and 6-9), the Tosco II oil shale retort is 28.4.% of C_{TDC} and the upgrader is 24.3%. The Paraho Direct retort is 15.5% of C_{TDC} and the upgrader is 28.9%.

In the Red Leaf process, oil shale is mined, rubblized, and deposited into a lined capsule with embedded heating pipes. Produced gases and liquids are collected at the top and bottom of the capsule, respectively.

6.3.2 Supply Price Evaluation of Ex Situ Oil Shale Base Case

The supply price at a specified hurdle rate is computed by finding the real fixed price that results in NPV = 0 with the discount factor computed from the hurdle rate; see Section 5.2.2 for additional details.

6.3.2.1 Base Case Supply Prices

Base case supply prices as a function of hurdle rate are given in Table 6-10 for Tosco II air-fired combustion, in Table 6-11 for Tosco II oxy-fired combustion, and in Table 6-12 for Paraho Direct air-fired combustion. The tabulated supply costs from Tables 6-10 through 6-12 are plotted in Figures 6.14 through 6.16, respectively. All supply costs listed in Tables 6-10 through 6-12 are positive contributors to the supply price while all non-oil revenue streams are negative contributors.

The supply cost is computed by adding the total non-oil revenue per barrel to the supply price of oil per barrel. That is, the difference between the supply price and the supply cost of oil is the non-oil revenue per barrel.

Table 6-10. Supply price for Tosco II air-fired ex situ oil shale production scenario as a function of hurdle rate. Table footnotes apply to Tables 6-10, 6-11, and 6-12.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine [a]	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79
Retort	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36	$ 8.36
Upgrading [b]	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14	$ 13.14
Taxes	$ 10.73	$ 13.33	$ 16.61	$ 20.37	$ 24.62	$ 29.79	$ 35.77
Oil Royalties	$ 8.30	$ 9.19	$ 10.25	$ 11.47	$ 12.84	$ 14.45	$ 16.28
Net Earnings	$ -	$ 4.69	$ 10.16	$ 16.43	$ 23.51	$ 31.61	$ 40.75
Maintenance	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65	$ 13.65
Other [c]	$ 14.81	$ 14.86	$ 14.93	$ 15.01	$ 15.10	$ 15.20	$ 15.31
Supply Cost	**$ 78.79**	**$ 87.02**	**$ 96.90**	**$ 108.23**	**$ 121.02**	**$ 135.99**	**$ 153.06**
Other Revenue	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47
Oil Supply Price	**$ 77.32**	**$ 85.56**	**$ 95.43**	**$ 106.76**	**$ 119.55**	**$ 134.52**	**$ 151.60**

[a] *"Mine" includes costs for mining and size reduction/solids handling (e.g. crushing).*
[b] *"Upgrading" includes all costs associated with the fractionator, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.*
[c] *"Other" includes all costs associated with the oil pipeline, water pipeline, allocated costs for utility plants, water reservoir, site preparation, service facilities, contingency, permitting, research, administration, incentive compensation, insurance, intellectual property royalties, overhead, land, startup, and CO_2 compressor (oxy-firing only).*

Table 6-11. Supply price for Tosco II oxy-fired ex situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79
Retort	$ 13.52	$ 13.52	$ 13.52	$ 13.52	$ 13.52	$ 13.52	$ 13.52
Upgrading	$ 21.70	$ 21.70	$ 21.70	$ 21.70	$ 21.70	$ 21.70	$ 21.70
Taxes	$ 11.30	$ 14.04	$ 17.45	$ 21.36	$ 25.79	$ 31.17	$ 37.41
Oil Royalties	$ 9.84	$ 10.77	$ 11.87	$ 13.14	$ 14.57	$ 16.24	$ 18.15
Net Earnings	$ -	$ 4.89	$ 10.59	$ 17.10	$ 24.47	$ 32.87	$ 42.38
Maintenance	$ 14.10	$ 14.10	$ 14.10	$ 14.10	$ 14.10	$ 14.10	$ 14.10
Other	$ 18.12	$ 18.18	$ 18.25	$ 18.33	$ 18.42	$ 18.53	$ 18.65
Supply Cost	**$ 98.39**	**$ 106.99**	**$ 117.28**	**$ 129.05**	**$ 142.37**	**$ 157.93**	**$ 175.70**
Other Revenue	$ 6.74	$ 6.74	$ 6.74	$ 6.74	$ 6.74	$ 6.74	$ 6.74
Oil Supply Price	**$ 91.65**	**$ 100.26**	**$ 110.54**	**$ 122.32**	**$ 135.63**	**$ 151.19**	**$ 168.97**

Table 6-12. Supply price for Paraho Direct air-fired ex situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32
Retort	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12	$ 9.12
Upgrading	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41	$ 18.41
Taxes	$ 8.84	$ 10.97	$ 13.61	$ 16.64	$ 20.07	$ 24.24	$ 29.05
Oil Royalties	$ 8.42	$ 9.14	$ 9.99	$ 10.97	$ 12.08	$ 13.37	$ 14.84
Net Earnings	$ -	$ 3.79	$ 8.19	$ 13.24	$ 18.94	$ 25.44	$ 32.78
Maintenance	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87	$ 10.87
Other	$ 12.87	$ 12.92	$ 12.98	$ 13.04	$ 13.11	$ 13.19	$ 13.28
Supply Cost	**$ 79.85**	**$ 86.53**	**$ 94.49**	**$ 103.60**	**$ 113.91**	**$ 125.95**	**$ 139.67**
Other Revenue	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47	$ 1.47
Oil Supply Price	**$ 78.38**	**$ 85.06**	**$ 93.02**	**$ 102.13**	**$ 112.44**	**$ 124.48**	**$ 138.20**

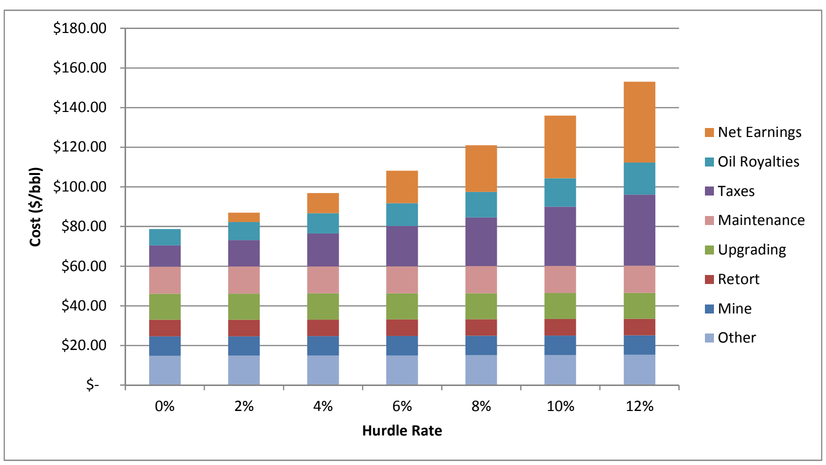

Figure 6.14: Supply cost for Tosco II air-fired ex situ oil shale production scenario as a function of hurdle rate.

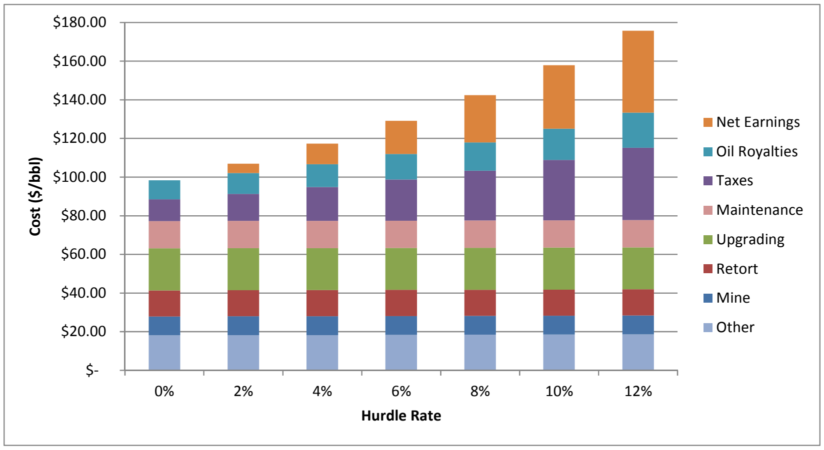

Figure 6.15: Supply cost for Tosco II oxy-fired ex situ oil shale production scenario as a function of hurdle rate.

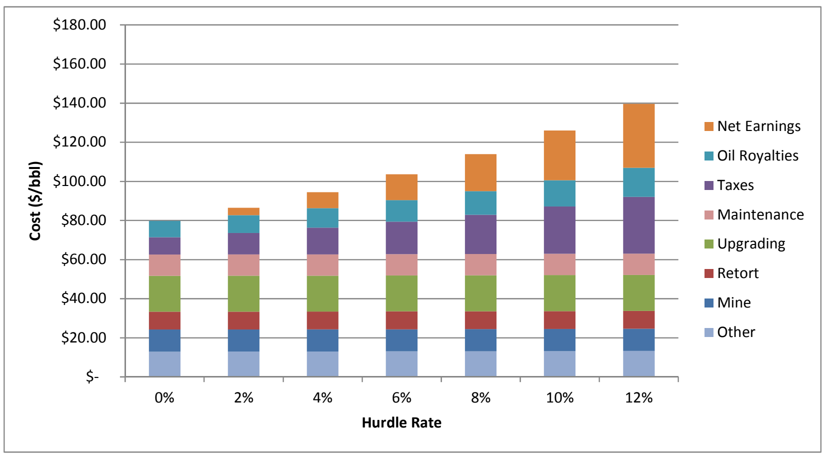

Figure 6.16: Supply cost for Paraho air-fired ex situ oil shale production scenario as a function of hurdle rate.

The supply price to produce refinery-ready SCO is $77.32–$151.60/bbl for the Tosco II air-fired case, $91.65–$168.97/bbl for the Tosco II oxy-fired case, and $78.38–$138.20 for the Paraho Direct air-fired case. These supply prices include (1) all costs (capital and operating expenses, taxes, royalties, net earnings computed from the hurdle rate) to produce SCO and transport it to market and (2) all non-oil revenue streams. The supply cost at a hurdle rate of 0% represents the usual cost, that is, the cost of the project without any profit for the investor(s).

Comparing the Tosco II results, the higher costs associated with oxy-fired combustion (an increase of approximately $20–$23/bbl) are somewhat offset by the sale of CO_2 ($5.27/bbl), resulting in supply prices for the oxy-fired case that are approximately $14–$17/bbl more than for the air-fired cased.

The supply price differences between the Tosco II and Paraho Direct air-fired processes vary as a function of hurdle rate. This variation is driven by differences in capital and operating costs. In general, the Tosco II process has higher capital costs and lower operating costs than the Paraho Direct process. As a result, maintenance costs, which are computed as a percentage of C_{TDC}, are lower for the Paraho Direct process. The higher capital costs of the Tosco II process result from the mechanical complexity of the retort. The higher operating costs of the Paraho Direct process are primarily driven by the large volumes of natural gas that must be purchased to supplement gaseous fuel produced in the retort. If the hurdle rate is low, then capital is cheap and lower operating costs favor the Tosco II case. However, at higher hurdle rates, capital becomes more expensive, and the cash flow advantage of the Tosco II process no longer outweighs the disadvantage of its higher capital cost.

It is assumed that the Tosco II retort produces an off-gas that is pure methane while the Paraho Direct retort off-gas is a low-quality fuel (e.g. low Btu content) due to dilution by air and combustion products.

For the Tosco II air-fired case at a 0% hurdle rate, the highest costs are for maintenance ($13.65/bbl), upgrading ($13.14/bbl), and taxes ($10.73/bbl). Taxes are tied to net earnings and oil royalties are tied to supply price, both of which rise with increasing hurdle rate. At a 12% hurdle rate, the highest cost categories are net earnings ($40.75/bbl), taxes ($35.77/bbl), and royalties ($16.28/bbl). When switching from an air-fired to an oxy-fired Tosco II system, the two cost categories that show the greatest increase at a 0% hurdle rate are retorting and upgrading, with $5/bbl and $8/bbl increases respectively. As a result, the highest cost category for oxy-firing (0% hurdle rate) is upgrading ($21.70/bbl), followed by maintenance ($14.10/bbl) and retorting ($13.52/bbl). At a 12% hurdle rate, the highest costs are for net earnings ($42.38/bbl), taxes ($37.41/bbl), and upgrading ($21.70).

These cost increases are driven by the cost of purchasing pure O_2, as will be detailed below.

For the Paraho Direct air-fired case at a 0% hurdle rate, the highest cost category, upgrading ($18.41), reflects the cost burden of purchasing so much natural gas; the mine ($11.32) and maintenance ($10.87) are second and third. As with the Tosco II case, the highest cost categories at a 12% hurdle rate, net earnings ($32.78) and taxes ($29.05), are those that are tied to the hurdle rate; upgrading ($18.41) is third. Taxes are lower for the Paraho Direct case than for the Tosco II case (0% hurdle rate) as a result of the way taxable income is computed. During the first four years of production, Tosco II has a lower taxable income than Paraho Direct because of depreciation on capital costs. However, by year nine, depreciation is no longer a factor and the higher operating expenses for Paraho Direct give it a lower taxable income. The net result is that per barrel taxes are 17–19% lower for the Paraho Direct scenario.

Taxing CO_2 at the rate of $25 per ton increases the Tosco II base case supply price for air-firing by $6.37 to $83.69/bbl at a 0% hurdle rate. This supply price is still less than the $91.65/bbl supply price for oxy-firing (0% hurdle rate). In order for the air-fired system to have the same supply price as the oxy-fired system and thus drive investment in CCS and EOR, CO_2 would have to be taxed at a rate of approximately $56 per ton.

6.3.2.2 Supply Costs that Vary with Hurdle Rate

The only supply costs that vary as a function of hurdle rate are those that are tied to the price of oil, namely taxes, royalties, incentive compensation, and net earnings. As shown in Figure 6.17, all of these costs have a linear relationship to the price of oil.

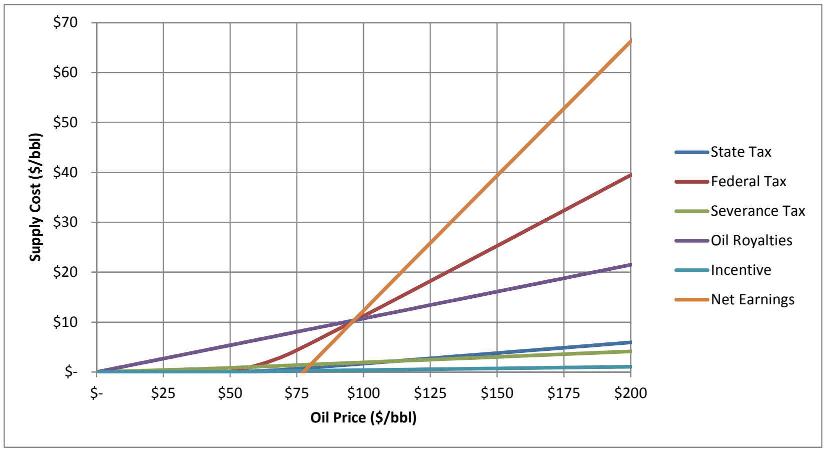

Figure 6.17: Supply cost ($/bbl) of cost components that are dependent on oil price.

Corporate income taxes (state and federal) and incentive compensation are zero until about $50/bbl, at which point the cash flow during production years becomes positive. However, the net earnings (a reflection of the NPV) stay negative until oil sells for at least $77/bbl for the air-fired base case and $92/bbl for the oxy-fired base case as shown in Tables 6-10 through 6-12.

6.3.2.3 Detailed Supply Price Breakdowns

Detailed supply price breakdowns for both air- and oxy-firing at a 0% hurdle rate are given in Tables 6-13 through 6-15. Due to rounding error, the "Total" column may differ from the sum across any given row by $0.01. Also, fuel cost in these tables refers only to natural gas and does not include diesel fuel and other types of fuels that might be necessary to operate mining equipment, vehicles, etc.

In evaluating Tables 6-13 and 6-14 (Tosco II process), costs for oxy-firing are $19.60/bbl more expensive than for air-firing, due mostly to the cost of O_2 ($13.87/bbl). The cost of electricity more than doubles to $2.13/bbl due to the electrical demand of the CO_2 compression system. Overall, the higher capital cost of the oxy-firing system propagates through all of the cost categories that are defined as fractions of capital cost, resulting in slight increases (tens of cents) in each category. As noted previously, these cost increases are partially offset by the sale of CO_2.

The differences in capital and operating expenses for the Tosco II and Paraho Direct processes are seen in the supply price breakdowns shown in Tables 6-13 and 6-15. For example, the capital cost for the Tosco II retort is $4.45 while for the Paraho Direct retort it is $1.93. In contrast, the electricity cost for the Tosco II retort is only $0.02 while for the Paraho Direct retort, it is $4.49. Also, the off-gas produced from both retorts is used to offset natural gas purchases for the hydrogen plant. The low quality of the Paraho Direct off-gas requires that more natural gas be purchased; the per barrel fuel (e.g. natural gas) cost is $11.04 for the Paraho Direct process and $5.37 for the Tosco II process. A third difference, though small, is seen in the costs for the sour water stripper. For the Tosco II process, the cost is $1.26/bbl while for the Paraho Direct process, it is $0.17. The overall reduced water usage of the Paraho Direct process results in less sour water that must be treated.

Table 6-13. Detailed supply price breakdown for Tosco II air-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Oil Shale Mine [a]	$ 2.39	$ 2.87	$ -	$ -	$ 0.01	$ -	$ -	$ 4.53	$ 9.79
	Oil Shale Retort	$ 4.45	$ 1.30	$ 0.02	$ 1.62	$ 0.32	$ 0.51	$ -	$ 0.14	$ 8.36
Upgrading	Hydrotreater	$ 3.07	$ 0.43	$ 0.47	$ 0.47	$ 0.00	$ -	$ -	$ 0.07	$ 4.51
	H_2 Plant	$ 0.32	$ 0.14	$ 0.04	$ 5.37	$ 0.08	$ -	$ -	$ -	$ 5.96
	Fractionator	$ 0.16	$ 0.05	$ 0.03	$ 0.19	$ 0.00	$ 0.07	$ -	$ -	$ 0.49
	Sour Water Stripper	$ 0.24	$ 0.10	$ 0.13	$ -	$ 0.00	$ 0.80	$ -	$ -	$ 1.26
	Amine Treatment Unit	$ 0.01	$ 0.10	$ 0.00	$ -	$ 0.00	$ 0.65	$ -	$ -	$ 0.75
	Sulfur Recovery Unit	$ 0.02	$ 0.14	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.17
Delivery	Oil Pipeline	$ 0.42	$ -	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ 0.54
Other	Water Pipeline	$ 0.04	$ -	$ 0.06	$ -	$ -	$ -	$ -	$ -	$ 0.10
	CO_2 Compressor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 0.28
		Chemicals for Retort	Water Reservoir	$ 0.12
		Refrigerant R-134a	Site Preparation	$ 1.07
		Operating cost model for mine	Service Facilities	$ 1.07
			Contigency	$ 2.05
	** Taxes includes:	State Tax	Permitting	$ 0.12
		Federal Tax	Maintenance	$ 13.65
		Severance Tax	Overhead	$ 2.18
		Property Tax	Research	$ 0.74
			Administration	$ 0.77
			Incentive Compensation	$ 0.24
			Insurance	$ 1.44
			Taxes**	$ 10.73
			Royalties - oil	$ 8.30
			Royalties - IP	$ 2.21
			Working Capital	$ -
			Land	$ 0.31
			Startup	$ 1.57
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 78.79**
			CO_2	$ -
			Export Steam	$ 1.38
			Petroleum Coke	$ -
			Sulfur	$ 0.09
		Non-Oil Revenue Subtotal		**$ 1.47**
Oil Supply Price				**$ 77.32**

Table 6-14. Detailed supply price breakdown for Tosco II oxy-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Oil Shale Mine [a]	$ 2.39	$ 2.87	$ -	$ -	$ 0.01	$ -	$ -	$ 4.53	$ 9.79
	Oil Shale Retort	$ 4.45	$ 1.30	$ 0.02	$ 1.62	$ 0.32	$ 0.51	$ 5.16	$ 0.14	$ 13.52
Upgrading	Hydrotreater	$ 3.09	$ 0.43	$ 0.52	$ 0.45	$ 0.00	$ -	$ 1.30	$ 0.07	$ 5.86
	H_2 Plant	$ 0.32	$ 0.14	$ 0.04	$ 5.17	$ 0.07	$ -	$ 6.83	$ -	$ 12.58
	Fractionator	$ 0.16	$ 0.05	$ 0.03	$ 0.18	$ -	$ 0.07	$ 0.58	$ -	$ 1.08
	Sour Water Stripper	$ 0.24	$ 0.10	$ 0.13	$ -	$ 0.00	$ 0.80	$ -	$ -	$ 1.26
	Amine Treatment Unit	$ 0.01	$ 0.10	$ 0.00	$ -	$ 0.00	$ 0.65	$ -	$ -	$ 0.75
	Sulfur Recovery Unit	$ 0.02	$ 0.14	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.17
Delivery	Oil Pipeline	$ 0.42	$ -	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ 0.54
Other	Water Pipeline	$ 0.04	$ -	$ 0.06	$ -	$ -	$ -	$ -	$ -	$ 0.10
	CO_2 Compressor	$ 0.27	$ 0.10	$ 1.22	$ -	$ 0.11	$ -	$ -	$ 0.59	$ 2.29
Notes	* Other includes:	Catalyst							Allocated Costs for Utility Plants	$ 0.39
		Chemicals for Retort							Water Reservoir	$ 0.12
		Refrigerant R-134a							Site Preparation	$ 1.09
		Operating cost model for mine							Service Facilities	$ 1.09
									Contigency	$ 2.12
	** Taxes includes:	State Tax							Permitting	$ 0.12
		Federal Tax							Maintenance	$ 14.10
		Severance Tax							Overhead	$ 2.25
		Property Tax							Research	$ 0.74
									Administration	$ 0.78
									Incentive Compensation	$ 0.25
									Insurance	$ 1.49
									Taxes**	$ 11.30
									Royalties - oil	$ 9.84
									Royalties - IP	$ 2.81
									Working Capital	$ -
									Land	$ 0.32
									Startup	$ 1.62
									Net Earnings	$ -
		Supply Costs Subtotal								**$ 98.39**
									CO_2	$ 5.27
									Export Steam	$ 1.38
									Petroleum Coke	$ -
									Sulfur	$ 0.09
		Non-Oil Revenue Subtotal								**$ 6.74**
Oil Supply Price										**$ 91.65**

Table 6-15. Detailed supply price breakdown for Paraho Direct air-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Oil Shale Mine [a]	$ 2.80	$ 2.87	$ -	$ -	$ 0.00	$ -	$ -	$ 5.64	$ 11.32
	Oil Shale Retort	$ 1.93	$ 1.30	$ 4.49	$ -	$ 0.18	$ 1.22	$ -	$ -	$ 9.12
Upgrading	Hydrotreater	$ 3.07	$ 0.43	$ 0.47	$ 0.96	$ 0.00	$ -	$ -	$ 0.07	$ 5.00
	H_2 Plant	$ 0.32	$ 0.14	$ 0.04	$ 11.04	$ 0.08	$ -	$ -	$ -	$ 11.62
	Fractionator	$ 0.16	$ 0.05	$ 0.03	$ 0.39	$ 0.00	$ 0.07	$ -	$ -	$ 0.69
	Sour Water Stripper	$ 0.03	$ 0.10	$ 0.01	$ -	$ 0.00	$ 0.03	$ -	$ -	$ 0.17
	Amine Treatment Unit	$ 0.01	$ 0.10	$ 0.00	$ -	$ 0.00	$ 0.65	$ -	$ -	$ 0.75
	Sulfur Recovery Unit	$ 0.02	$ 0.14	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.17
Delivery	Oil Pipeline	$ 0.42	$ -	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ 0.54
Other	Water Pipeline	$ 0.03	$ -	$ 0.03	$ -	$ -	$ -	$ -	$ -	$ 0.06
	CO_2 Compressor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes				
Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 0.34
		Chemicals for Retort	Water Reservoir	$ 0.07
		Refrigerant R-134a	Site Preparation	$ 0.83
		Operating cost model for mine	Service Facilities	$ 0.83
			Contigency	$ 1.63
	** Taxes includes:	State Tax	Permitting	$ 0.12
		Federal Tax	Maintenance	$ 10.87
		Severance Tax	Overhead	$ 1.83
		Property Tax	Research	$ 0.74
			Administration	$ 0.77
			Incentive Compensation	$ 0.19
			Insurance	$ 1.15
			Taxes**	$ 8.84
			Royalties - oil	$ 8.42
			Royalties - IP	$ 2.26
			Working Capital	$ -
			Land	$ 0.25
			Startup	$ 1.25
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 79.85**
			CO_2	$ -
			Export Steam	$ 1.38
			Petroleum Coke	$ -
			Sulfur	$ 0.09
		Non-Oil Revenue Subtotal		**$ 1.47**
Oil Supply Price				**$ 78.38**

As noted in Section 6.2.4, the cost of purchasing, delivering, and treating water is a minimal expense. It adds $0.63 to the supply price of oil for the Tosco II air-fired base case, $0.73 to that of the Tosco II oxy-fired base case, and $0.39 to that of the Paraho Direct air-fired case.

Total water costs can be determined by adding up the "Water" column entries, the "Water Pipeline" row entries, and the "Water Reservoir" entry.

6.3.3 Supply Price Evaluation for Production of Raw Shale Oil

The supply prices given in the previous section are for producing SCO delivered to refining markets in Salt Lake City. In this section, supply prices for producing raw shale oil at the plant gate are determined. To obtain these prices, the costs associated with upgrading and transportation to market are zeroed out in the Supply Price Method. Zeroing out unit operations also removes their operating requirements (electricity, water, fuel, etc.) and resizes utilities (water pipeline, reservoir, electricity substation, etc.) to match. However, by zeroing out these unit operations, the cost of treating waste streams (sour water, acid gases) from the retort is not included in the cost and produced gas from the retort is only partially utilized due to model constraints.

Excluded costs are those for the hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, sulfur recovery unit, CO_2 compressor (if applicable) and oil pipeline. Included costs are those for the mine, retort, water pipeline, reservoir, and all cost categories that are functions of other costs (service facilities, site preparation, land purchase, utility plants, etc.).

Table 6-16 lists, as a function of hurdle rate, the supply costs by category and the supply price for the Tosco II air-fired scenario. Table 6-17 shows the same set of data for the Paraho Direct air-fired scenario. Because there are no non-oil revenue streams, the supply price and supply cost are the same.

Table 6-16. Plant gate raw shale oil supply cost/price as a function of hurdle rate using Tosco II air-fired process.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79	$ 9.79
Retort	$ 8.38	$ 8.38	$ 8.38	$ 8.38	$ 8.38	$ 8.38	$ 8.38
Upgrading	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxes	$ 6.58	$ 8.20	$ 10.23	$ 12.56	$ 15.20	$ 18.40	$ 22.09
Oil Royalties	$ 5.12	$ 5.67	$ 6.33	$ 7.08	$ 7.94	$ 8.93	$ 10.07
Net Earnings	$ -	$ 2.91	$ 6.30	$ 10.19	$ 14.59	$ 19.61	$ 25.27
Maintenance	$ 8.42	$ 8.42	$ 8.42	$ 8.42	$ 8.42	$ 8.42	$ 8.42
Other	$ 9.28	$ 9.32	$ 9.36	$ 9.41	$ 9.46	$ 9.53	$ 9.60
Supply Cost	**$ 47.57**	**$ 52.69**	**$ 58.81**	**$ 65.84**	**$ 73.78**	**$ 83.06**	**$ 93.62**
Other Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oil Supply Price	**$ 47.57**	**$ 52.69**	**$ 58.81**	**$ 65.84**	**$ 73.78**	**$ 83.06**	**$ 93.62**

Table 6-17. Plant gate raw shale oil supply cost/price as a function of hurdle rate using Paraho air-fired process.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32	$ 11.32
Retort	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13
Upgrading	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxes	$ 4.80	$ 5.99	$ 7.45	$ 9.12	$ 11.02	$ 13.32	$ 15.95
Oil Royalties	$ 4.66	$ 5.05	$ 5.53	$ 6.07	$ 6.68	$ 7.39	$ 8.20
Net Earnings	$ -	$ 2.09	$ 4.53	$ 7.32	$ 10.47	$ 14.07	$ 18.12
Maintenance	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ 5.95
Other	$ 7.47	$ 7.50	$ 7.53	$ 7.56	$ 7.60	$ 7.64	$ 7.69
Supply Cost	**$ 43.34**	**$ 47.03**	**$ 51.44**	**$ 56.48**	**$ 62.17**	**$ 68.84**	**$ 76.37**
Other Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oil Supply Price	**$ 43.34**	**$ 47.03**	**$ 51.44**	**$ 56.48**	**$ 62.17**	**$ 68.84**	**$ 76.37**

Keeping in mind that supply costs listed here do not include the cost of treatment of waste streams, the "plant gate" costs for raw shale oil in these tables are substantially lower than the costs in Tables 6-10 and 6-12 that include upgrading to a WTI-quality SCO and transportation to market. Since there is no market price for raw shale oil, it is difficult to estimate what kind of discount relative to WTI a producer might receive if there were a market for such a product. In addition, transportation costs for a raw shale oil would be higher than for SCO due to oil properties that increase pipeline construction and maintenance costs. What the data in these tables do illustrate is the range of supply prices that can be obtained depending on what costs are included in the calculation and what the assumed product is.

6.3.4 Net Present Value for Various Price Forecasts

In this section, the profitability of the two air-fired base cases are measured using the NPV Method. The NPV Method requires an oil price forecast and a specified hurdle rate. The NPV is then computed from Equation (5.3) with the hurdle rate being used to discount the cash flows (see Section 5.2.3). Table 6-18 lists the Tosco II NPV computed from three different EIA energy price forecasts for hurdle rates ranging from 0–16.5%. The hurdle rate for which NPV = 0 is defined as the IRR. For the EIA reference forecast, the IRR is 10.1% while for the EIA high forecast, the IRR is 16.5%. Table 6-19 lists the Paraho Direct NPV for hurdle rates ranging from 0–18.9% under the three price forecasts. The IRR is 11.6% for the EIA reference forecast and 18.9% for the high forecast. There is no IRR associated with the EIA low forecast in either table as all values of NPV are negative.

Table 6-18. NPV of Tosco II air-fired base case scenario (in billions of 2012 US$).

Hurdle Rate	EIA Price Forecast		
	Low	Reference	High
0.0%	$ (2.96)	$ 10.64	$ 21.29
2.0%	$ (3.45)	$ 6.93	$ 15.07
4.0%	$ (3.76)	$ 4.30	$ 10.64
6.0%	$ (3.95)	$ 2.41	$ 7.42
8.0%	$ (4.06)	$ 1.04	$ 5.06
10.0%	$ (4.12)	$ .03	$ 3.30
10.1%	$ (4.12)	$ -	$ 3.24
12.0%	$ (4.14)	$ (.72)	$ 1.97
16.5%	$ (4.09)	$ (1.80)	$ -

Table 6-19. NPV of Paraho Direct air-fired base case scenario (in billions of 2012 US$).

Hurdle Rate	EIA Price Forecast		
	Low	Reference	High
0.0%	$ (3.26)	$ 10.35	$ 20.97
2.0%	$ (3.44)	$ 6.93	$ 15.05
4.0%	$ (3.54)	$ 4.51	$ 10.82
6.0%	$ (3.58)	$ 2.77	$ 7.75
8.0%	$ (3.59)	$ 1.50	$ 5.49
10.0%	$ (3.57)	$ .56	$ 3.81
11.6%	$ (3.55)	$ -	$ 2.78
12.0%	$ (3.54)	$ (.13)	$ 2.53
18.9%	$ (3.36)	$ (1.47)	$ -

The NPV values seen in Tables 6-18 and 6-19 can be interpreted several different ways. One, for a given combination of price forecast/hurdle rate, an operation that has a negative NPV is not profitable while an operation with a positive NPV is profitable. In other words, any operation with NPV less than zero will return subnormal profits (profits less than the specified hurdle rate) and operations with NPV greater than zero will return supernormal profits (profits greater than the specified hurdle rate). Two, for a given price forecast, any hurdle rate greater than the IRR implies that the operation is not profitable while any hurdle rate less than the IRR indicates a profitable operation. Third, the Paraho Direct process is a more profitable operation as the IRR is greater than that of the Tosco II process for both the EIA reference and high forecasts.

From the data in Tables 6-18 and 6-19, neither air-fired base case is profitable under the low energy price forecast at any value of the hurdle rate; that is, the NPV is negative over the entire range. Losses shrink as the hurdle rate increases because higher hurdle rates give larger discounts to cash flows each year (which are always negative given the low price for oil). Under the low forecast, Tosco II losses approach a limit of -\$1.38 billion as the hurdle rate goes to infinity while Paraho Direct losses approach -\$1.03 billion.

Under the reference energy price forecast, the NPV is positive for values of hurdle rate ≤ 10.1% (Tosco II) and ≤ 11.6% (Paraho Direct), indicating that the operation is profitable if investors are willing to accept rates of return that may not reflect project risk. Under the high energy price forecast, the NPV is positive for hurdle rates up to 16.5% (Tosco II) and 18.9% (Paraho Direct). These values of IRR provide investors with a higher rate of return more commensurate with the risk level of these types of projects. In a 1984 economic evaluation of oil shale and oil sands resources located in Utah, Wells et al. [40] comment on the level of risk and the IRR for these types of projects: Given the economic conditions at the time and data available to them, the investment in these types of projects did not "offer the required rate of return to qualify as a rationally acceptable investment." Risks they list include untested technology, uncertain markets, insufficient resource characterization, and huge capital requirements. Hence, the steps to reducing risk for these types of projects include large-scale technology demonstrations, resource characterization at a finer granularity both vertically and horizontally, and reduction of capital costs through improved technology/efficiency.

6.3.5 Supply Price Sensitivity

Using the Supply Price Method, the sensitivity of the Tosco II supply price (e.g. break even price) of oil to a variety of parameters is investigated. These parameters include the oil shale grade, the capital and operating costs of the retort, H_2 consumption during upgrading, maintenance costs, site preparation and service facility capital expenses, fuel expenses (e.g. natural gas), and tax and royalty rates applied to the operation. For each of these parameters, a range of values relative to the base case is assumed (see Table 6-20) and the resulting supply price is computed. The Paraho Direct retort is included in the range of retort capital and operating expenses that is examined. Table 6-20 lists the supply price as a function of hurdle rate for the parameters tested.

While there is a high degree of uncertainty in labor costs (see Section 6.1.14), labor is not a large contributor to the supply cost of oil (\$5.14/bbl), so it is not investigated as part of this sensitivity study.

Table 6-20. Sensitivity of supply price for Tosco II ex situ oil shale scenario to various parameters.

Tosco II Ex Situ Oil Shale (Air-Fired)		Supply Price of Oil ($/bbl)			
		Hurdle Rate			
Variable	**Range**	**0%**	**4%**	**8%**	**12%**
Base Case	---	**$ 77.32**	**$ 95.43**	**$ 119.55**	**$ 151.60**
Shale Grade (GPT)	**25**				
Low	10	$ 125.39	$ 152.19	$ 187.83	$ 235.25
High	40	$ 63.00	$ 78.25	$ 98.56	$ 125.53
Retort - Capital & Op. Expenses	**100%**				
Low	50%	$ 62.08	$ 76.44	$ 95.55	$ 120.88
High	150%	$ 92.47	$ 114.31	$ 143.39	$ 182.10
Paraho	---	$ 78.38	$ 93.02	$ 112.44	$ 138.20
Upgrading H_2 Consumption (SCF/bbl)	**2,000**				
Low	1,000	$ 67.63	$ 85.51	$ 109.37	$ 141.02
High	3,000	$ 86.71	$ 105.00	$ 129.30	$ 161.61
Maintenance (% of C_{TDC})	**5%**				
Low	2%	$ 66.23	$ 83.99	$ 107.83	$ 139.89
High	8%	$ 88.43	$ 106.88	$ 131.32	$ 163.30
Site Prep. & Service Facilities (% of C_{TBM})	**20%**				
Low	10%	$ 73.27	$ 90.01	$ 112.29	$ 141.88
High	30%	$ 81.37	$ 100.86	$ 126.81	$ 161.32
Fuel Costs	**100%**				
Low	50%	$ 72.79	$ 90.86	$ 114.94	$ 146.92
High	150%	$ 81.85	$ 100.01	$ 124.16	$ 156.27
Royalties (% of Sales) [a]	**5.0%-12.5%**				
Federal Land [b]	12.5%	$ 79.21	$ 98.17	$ 123.78	$ 157.33
SITLA [c]	8.0%-12.5%	$ 77.39	$ 95.58	$ 119.94	$ 152.00
Low [d]	5.0%	$ 73.12	$ 90.52	$ 114.01	$ 144.71
Federal Taxes (% of Taxable Income) [e]	**35%**				
Low [f]	15%	$ 73.46	$ 88.31	$ 108.15	$ 133.31
State Taxes (% of Taxable Income) [g]	**5%**				
SB65 Tax Credit [h]	< 2%	$ 76.75	$ 94.44	$ 118.04	$ 149.07
Combined	---				
All Unfavorable [i]	---	$ 217.30	$ 256.22	$ 308.37	$ 376.02
All Favorable [j]	---	$ 30.81	$ 39.40	$ 50.98	$ 65.72

[a] *Royalty rate given in 2008 royalty rules; see Section 3.4.1.1*
[b] *Standard fixed rate for conventional oil lease*
[c] *Royalty rate for oil shale/oil sands leases on state (SITLA) lands, see Section 3.4.1.1*

[d] *Lowest royalty rate proposed on either federal or state lands*
[e] *Federal corporate income tax rate based on taxable income*
[f] *Lowest federal corporate income tax rate*
[g] *Standard state corporate income tax*
[h] *State corporate income tax rate after state tax credit is applied; see Section 3.4.4*
[i] *All favorable = High bitumen saturation, high bitumen/solvent recovery, low H_2 requirement,ow maintenance costs, low fuel costs, 5% royalty rate, federal income tax of 15%, state tax credit applies*
[j] *All unfavorable = Low bitumen saturation, low bitumen/solvent recovery, high H_2 requirement, high maintenance costs, high fuel costs, 12.5% royalty rate*

Over the ranges of parameters tested, the grade of oil shale processed has the largest impact on the Tosco II supply price. Shale grade determines the volume of rock that must be mined and retorted, impacting the capital and operating costs of both unit operations. High quality shales would lower the economic barriers to production, or conversely, high oil prices could make recovery of shale oil from lower quality shales economically feasible. A 1984 report by Wells et al. [40] reaches a similar conclusion: "A valuation based on discounted cash flow methods is extremely sensitive to the grade of the source material...and to the market price of the synthetic crude oil produced." Assuming the average price from the reference oil price forecast of $131.85/bbl (see Table 6-22 in Section 6.3.6), an operation processing 40 GPT oil shale is profitable (e.g. positive NPV) for values of hurdle rate up to 13.1%. Under the high oil price forecast (average price of $192.45), profitability is achieved for hurdle rates up to 19.7%. For the low oil shale grade (10 GPT), the operation is profitable up to hurdle rates of 1.9% and 9.1% under the reference and high oil price forecasts, respectively.

Since several oil shale retorting technologies have been utilized in industrial practice with various claims regarding their capital and operating costs (see Figure 6.5), the impact of having a retort that is 50% more or less expensive to build and operate than the base case is investigated. This change in retorting expenses has the second largest impact on the supply price. For a hurdle rate of 12%, changing the retorting costs by ± 50% increases or decreases the costs by approximately $31/bbl; this difference is ± $15/bbl at a 0% hurdle rate. The effect of employing Paraho Direct rather than Tosco II retort technology retort is most pronounced at the highest hurdle rate due to the relative impact of capital and operating costs as explained in Section 6.3.2. At a 0% hurdle rate, the supply price difference is negligible; this difference increases to more than $13/bbl at a 12% hurdle rate. Based on retort capital costing data in STRAAM [7], it is likely that this report is underestimating the capital cost of the retorts as shown in Figure 6.5 at the 50,000 BPD scale. With a Tosco II retort that costs 150% of the base case, the process is still profitable under the reference and high oil price forecasts (for hurdle rates 7.0% and ± 13.5%, respectively).

Estimates of the H_2 consumed during hydrotreating of shale oils similar to the type that would be produced in this process range from 1,500 to 2,200 SCF per barrel (42.5–62.3 cubic meters per barrel) [13,14]. Since the amount of H_2 consumed plays a major role in determining the costs of the upgrading process, H_2 consumption is varied from the base case value of 2,000 SCF per barrel by ± 50%. These variations shift the supply price by about $10/bbl.

Maintenance costs are estimated as a percentage of C_{TDC}, but exactly what percentage to use varies from a low of 2% [21] to a high of 11.5% [8]. Since C_{TDC} is in the billions of dollars, maintenance costs are on the order of hundreds of millions of dollars per year, and the choice of maintenance percentage can have a significant impact on the total supply price. However, the impact of maintenance costs is less than that of oil shale grade or retort cost, especially at higher hurdle rates, since it affects operating but not capital costs.

Site preparation and service facilities are generic capital expenses that are estimated solely as a fraction of C_{TBM} and are included in Seider's methodology to cover the costs of everything from land surveys to building medical facilities [8]. The recommendation for the cost of these two line items ranges from 4–20% of C_{TBM} for site preparation and 5–20% of C_{TBM} for service facilities, depending on the amount of pre-existing development at the site. The selection of these percentages are somewhat arbitrary and the resultant changes in capital expenses quite large (tens of millions to hundreds of millions of dollars). The percentages selected for the base case (10% each) represent the lower limit for green sites (i.e. locations with no pre-existing infrastructure). The low percentages in the sensitivity analysis (5% each) would be typical for making an addition to an integrated complex, while the high percentages (15% each) are in the mid-range of costs for green sites. Over this range of capital costs for site preparation and service facilities, the supply price changes by ± \$4–\$10 bbl. Higher hurdle rates are affected more strongly because discounts to cash flow in later years of the project weight cash flows during the construction phase more heavily.

Of all the utilities, fuel (e.g. natural gas) is the only significant contributor to the supply price. Altering the fuel costs ± 50% moves the supply price by ± \$4–\$5/bbl, reflecting the impact of changes in either fuel purchase price or utilization (due to a process being much more or less efficient). It should be noted that this variation only affects the cost of the makeup fuel required, after accounting for the heating value of waste fuel gases from the fractionator (which supply 41% of the total heating requirement for the Tosco II process).

For the Tosco II base case, fuel costs are four times larger than steam costs and one order of magnitude larger than electricity or water costs.

Royalties and taxes are included in the sensitivity study as they are costs imposed by government policies which could be changed to encourage or discourage development. Table 6-20 shows the supply price for oil assuming a range of royalty and tax rates/credits that federal and state governments have suggested for oil shale and/or conventional oil development. The impact of tax and royalty policies increases as the hurdle rate (and thus net earnings) increase. Because the federal corporate income tax rate is much larger than that of the state, changes to federal tax policy have a much larger impact on supply price than the recent change to Utah state tax policy in the form of a tax credit for alternative energy development (see Section 5.4.3). The effect of royalties and taxes higher than the base case was not investigated as such an increase appears unlikely given current political trends.

Finally, the combined effect on the supply price of applying all the favorable and unfavorable parameters in Table 6-20 is given as a function of hurdle rate. These "Most favorable" and "Most unfavorable" prices provide outer bounds on the supply price for this scenario given the parameter ranges tested.

6.3.6 Analysis and Summary

Based on results presented in this scenario, questions may arise such as "How do these results compare with results published elsewhere?" or "How is oil shale production economically viable at today's oil prices?" or "What is the energy return on energy invested (EROI)?" These questions are addressed in this section. Also, the question on economic viability is implicitly addressed in the sensitivity analysis above (i.e. how assumptions about various system parameters impact the computed supply price).

Comparisons of the supply prices given in Sections 6.3.2 and 6.3.3 with other published numbers must be undertaken carefully as cost categories, definitions, and methodologies for determining profitability vary widely. Terms such as "break even price," "netback," "all in production cost," and "cost estimate" may not directly equate to the supply price definition used in this report. Table 6-21 compares prices/costs from other studies; cost categories are marked to indicate whether or not they are included in a particular estimate. Reported capital costs per barrel are added to the "Cost/Price Estimate" since this report includes capital costs in the supply price.

Table 6-21. Comparison of reported prices/costs for ex situ oil shale production. All numbers are adjusted to 2012 US$ using an annual inflation rate of 1.8%.

x = included
- = not included
? =Unknown whether this category is included or not

Study/Source	Cost/Price Estimate ($/bbl)	Scale (BPD)	Extraction	Upgrading	Delivery	Taxes	Royalties	Net Earnings
Loucks	$60.19	50,000	x	x	x	-	-	-
OSEC[a] [41]	$41–$48	50,000	x	x	?	?	?	?
RAND[b] [38]	$79–$108	50,000	x	x	x	x	x	x
Red Leaf[c] [39]	$64.69–$86.66	9,500	x	-	x	x	x	x
This report - Tosco II[d]	$95.43–$151.60	50,000	x	x	x	x	x	x
This report - Paraho Direct[e]	$93.02–$138.20	50,000	x			x	x	x
This report- Tosco II (plant gate)[f]	$58.81–$93.62	50,000	x			x	x	x

[a] The numbers reported by OSEC are "all in production costs," but it is unclear if that cost includes delivery, taxes, royalties, and net earnings.
[b] The net earnings rate assumed for the RAND analysis is 10%.
[c] The price range reported by Red Leaf reflects different assumptions about the price of WTI. Assuming $60/bbl WTI, the net earnings are $25.35; for $80/bbl WTI, the net earnings are $38.90 (all in 2015 US$). These prices are deflated back to 2010 US$ assuming 2% inflation, the reported capital cost of $2.66/bbl added in, and the resulting prices inflated to 2012 US$ using a 1.8% inflation rate. Red Leaf has reported that shale oil produced from its retort is of WTI quality without upgrading.
[d] The range represents values of hurdle rate from 4–12% for the Tosco II air-fired scenario.
[e] The range represents values of hurdle rate from 4–12% for the Paraho Direct air-fired scenario.
[f] The "plant gate" supply price range represents values of hurdle rate from 4–12% for the Tosco II air-fired scenario. The supply price excludes costs associated with upgrading and transportation to market.

The range of supply price values for the base case Tosco II and Paraho Direct scenarios in this report are higher than those found in other published sources. However, it is difficult to determine whether or not two cost estimates are on the same basis. For example, this report and the data from the RAND report clearly include all costs for delivering a WTI-quality SCO to market; information from other sources may not be so explicit. Table 6-21 also lists the "plant gate" supply price for Tosco II, which excludes upgrading and transportation to market ("Delivery" in Table 6-21). Its supply price range is similar to that reported by commercial entities. Nevertheless, as seen in the Table 6-21 and in the sensitivity analysis (Table 6-20), supply prices vary widely as a function of the assumptions that are made.

Economic viability is determined by project revenue as well as project costs. The average and range of oil prices in each of the three EIA oil price forecasts for WTI are reproduced in Table 6-22. Under the low forecast, EIA is predicting that oil prices will be going down over the long term. If the retorting/upgrading process were to produce (1) a premium SCO to sell to a refiner or (2) a diesel fuel to sell directly to a distributor, the price obtained for the product might exceed WTI prices. As an example, Figure 6.18 shows the historical comparison of the relative value of Brent crude and ultra-low-sulfur diesel to WTI.

See Figure 5.3 for projected oil prices from the present to 2035.

Table 6-22. Average and range of oil prices for each EIA oil price forecast for WTI (in 2012 US$).

Oil Price Forecast	Average Price ($/bbl)	2012 Price ($/bbl)	2035 Price ($/bbl)
Low	$63.87	$73.01	$64.65
Reference	$131.85	$98.17	$150.24
High	$192.45	$144.28	$207.64

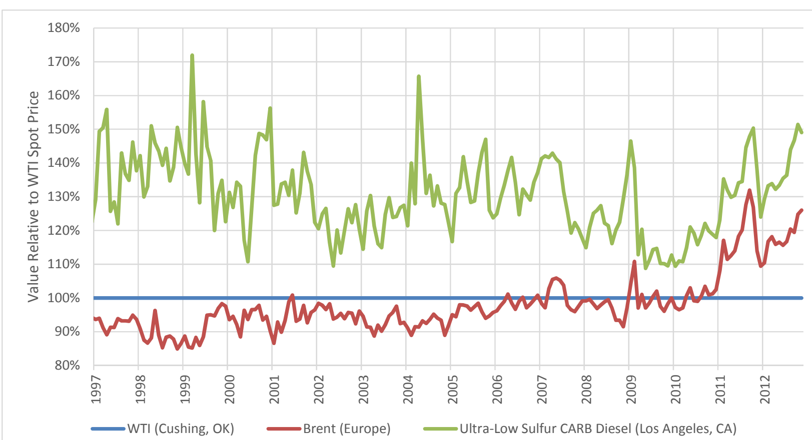

Figure 6.18: Price of Brent crude and ultra-low-sulfur diesel compared to WTI; data from EIA [42].

Based on the data trends in Figure 6.18, project revenue could be increased depending on the quality of product that was brought to market and on expanded market opportunities. Currently, the Salt Lake City refineries are the only market for crudes produced in the Uinta Basin. If other markets opened up, project revenues would expand accordingly.

The EROI is the ratio of usable energy gained from an energy resource to the energy used (directly and indirectly) to obtain that resource. The EROI for the Tosco II and Paraho Direct ex situ oil shale production scenarios has been estimated by dividing the energy output (SCO) by the energy inputs, including (1) the electricity and natural gas use for each of the processes described in this section, and (2) the energy required for mining and transporting the oil shale, steam generation, water delivery, and O_2 production (for the oxy-fired case). These EROI estimates do not include the energy required for facilities construction, water treatment or refrigeration. Based on this methodology, the EROI is 3.89 for the Tosco II air-fired case, 3.78 for the Tosco II oxy-fired case, and 2.39 for the Paraho Direct air-fired case. Additional details about these EROI numbers are found in Kelly et al. [30].

The fuel higher heating value is used as the basis for all energy inputs and outputs.

In conclusion, the purpose of this analysis not to comment on the economic viability of any particular oil shale development scenario but to provide a transparent overview of the factors that impact profitability. By clearly stating the assumptions made and the results obtained based on those assumptions, it is hoped that the issues surrounding profitability analysis for oil shale development are clarified.

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7 In Situ Oil Shale Production Scenario

7 In Situ Oil Shale Production Scenario

This section provides a profitability analysis for producing SCO from Utah oil shale using an in situ extraction process. In situ production occurs by underground heating to extract oil from the oil shale followed by pumping of the produced oil to the surface. The design production capacity is 50,000 BPD, but this production volume is only achieved in the final years of the 24-year project due to the long time delay between the initiation of underground heating and the maximum production rate. This scenario is developed using commercially-available reservoir simulation tools and equipment that can be purchased "off-the-shelf" and does not necessarily represent what might be achievable using technologies currently under development.

The scenario is located near Bonanza, Utah, across the White River from the ex situ extraction operation discussed in Section 6. This location was chosen based on a recently completed UGS analysis of Uinta Basin oil shale resources [1]. Figure 7-1 is the same isopach map of the Uinta Basin presented in Figure 6-1 with the location of the in situ oil shale development scenario marked. It shows how the thickness of the 25 GPT oil shale zone varies across the basin. The most promising area for development due to the thickness of the available resource is the northeast section, corresponding to the basin depocenter, so both ex situ and in situ oil shale scenarios are located in this area.

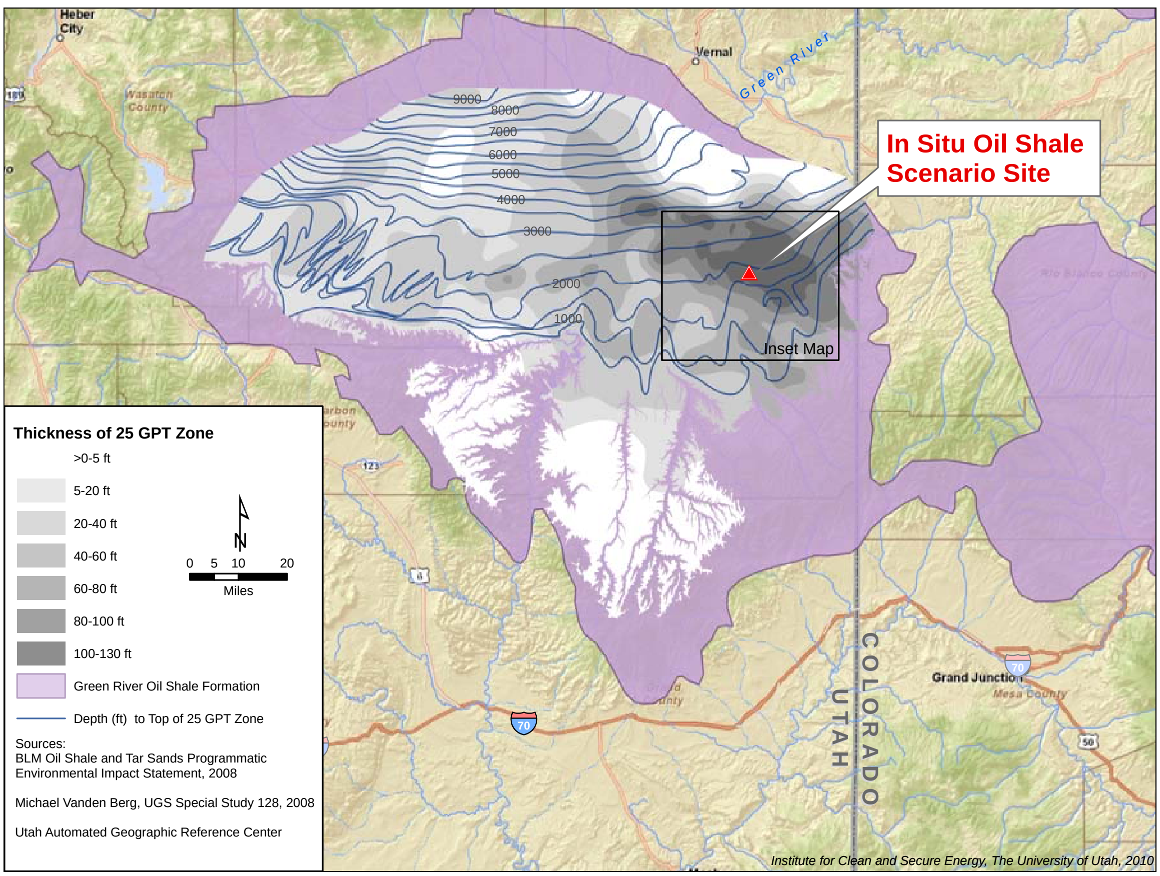


Figure 7.1: Isopach and overburden thickness for 25 GPT oil shale with location of in situ oil shale scenario identified; adapted from [1].

Due to the depth of the resource (500–1000 feet or 152–305 meters), the 60–130 foot (18–40 meter) thickness of the 25 GPT zone, and an impervious shale layer above the deposit, underground heating is a logical approach for the extraction of this resource. However, in practice, a continuous layer of this thickness does not exist; the formation has laminations that will have an impact on production.

Refer to Figure 6.3 for an example of the oil yield as estimated by bulk density from a well drilled in the northeast section of the Uinta Basin.

Figure 7.2, an inset map of the area delineated by the square in Figure 7.1, shows land ownership in the near vicinity of the scenario location. It is a mix of federal (BLM), state (SITLA), tribal, and private land, with the accompanying ramifications of such land ownership patterns. The scenario is located on BLM land, so the federal government is the landowner for the purposes of determining tax and royalty payments (see Section 3.4).

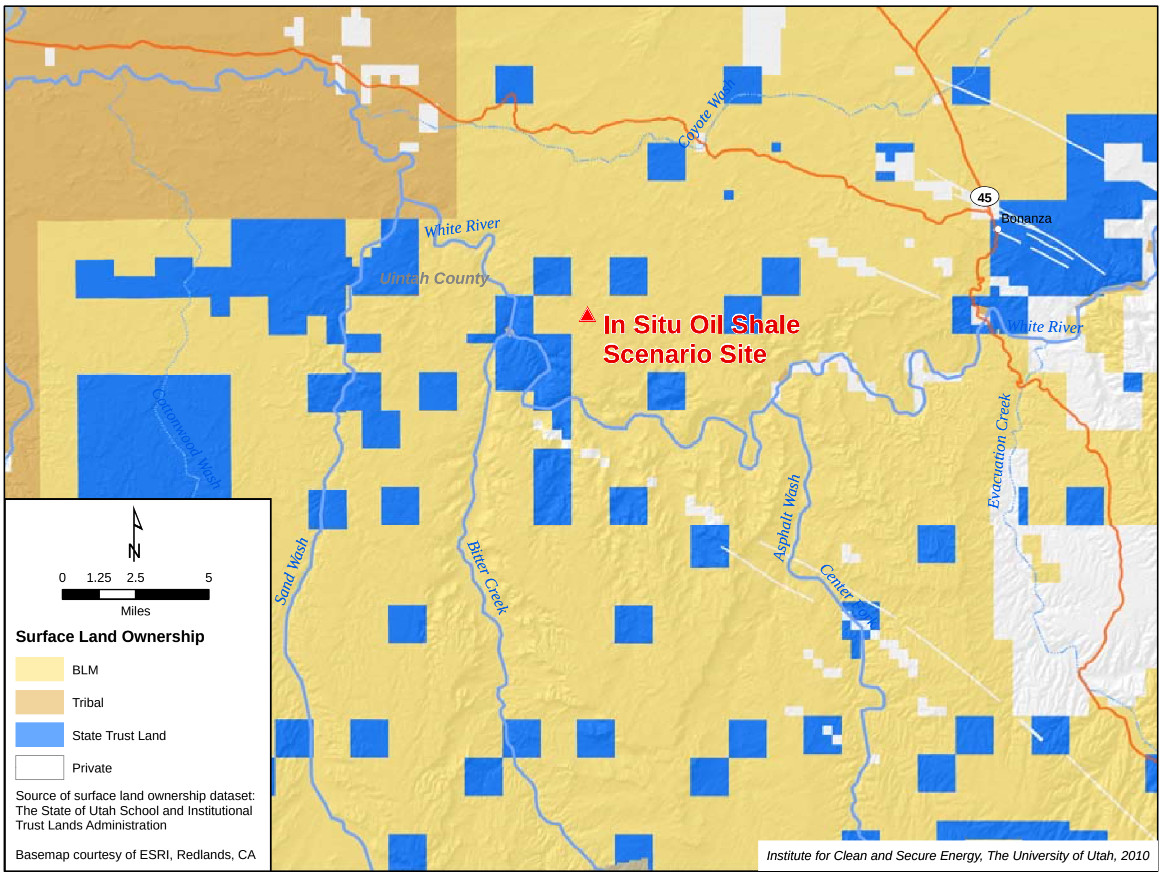


Figure 7.2: Land ownership in the northeast Uinta Basin near the in situ oil shale scenario site.

7.1 Description of Unit Operations

The overall in situ oil shale scenario is shown in Figure 7.3. Both air- and oxy-fired combustion systems are used to supply heat for this scenario; the dashed lines in Figure 7.3 are for processes that only apply to oxy-firing. Each block in the figure represents a unit operation that is discussed in the subsections that follow. For each unit operation, a brief description of the process is given followed by a description of the inputs and models needed

The portable electrical generators (see Section 7.1.1.4) are not included in the suite of oxy-fired processes because the cost information received from the manufacturer is for air-fired technology only.

to estimate the capital and operating costs. Figure 7.3 and the analysis in this section provide a general overview of the processes involved in the production of SCO from the in situ heating of oil shale and are not an exhaustive list of all unit operations that would be required.

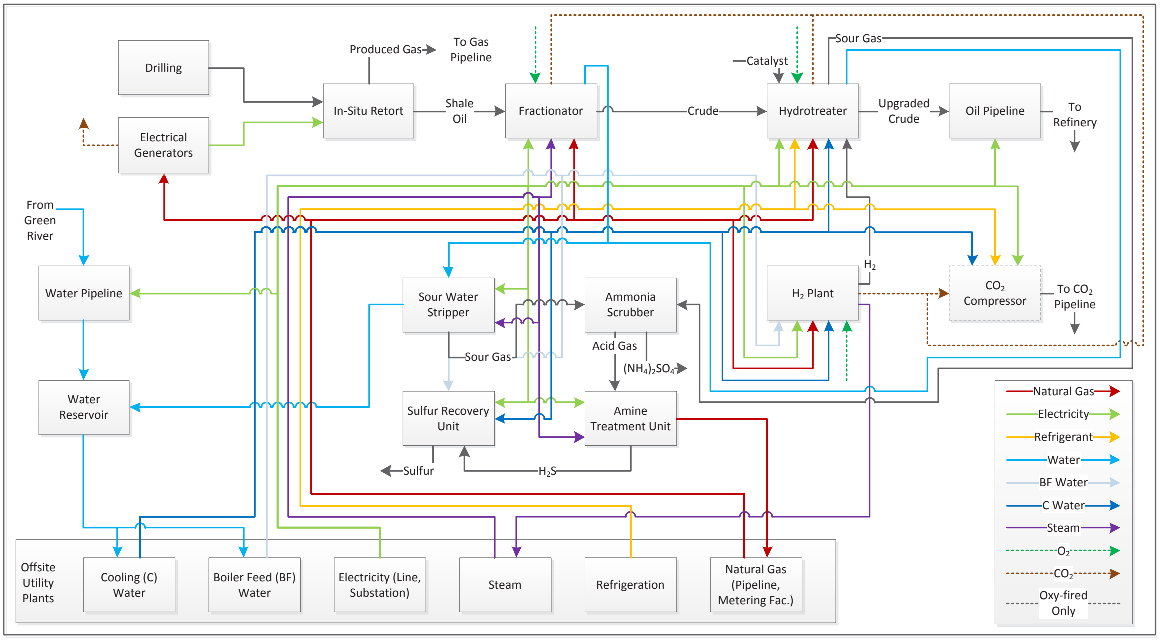


Figure 7.3: In situ oil shale production process overview.

Unless otherwise noted, all unit operations are located at the scenario site near Bonanza, Utah.

7.1.1 In Situ Retorting

In situ retorting technologies have been demonstrated at various scales over the past decade. A summary of recent work can be found in Table II of Chapter 2 in "Oil Shale: A Solution to the Liquid Fuel Dilemma" [2], with additional details about AMSO's Conduction, Convection, and Reflux process, Shell's ICP process, and ExxonMobil's Electrofrac process found in subsequent chapters [3–5]. Nevertheless, none of these processes has reached the point of commercial production, so there is no industry data from which to obtain cost estimates.

In this scenario, conductive heating with electrical resistance heaters is the technology of choice because the heaters are commercially available and costs/operational requirements can be obtained. Downhole heating with electrical resistance heaters is a common EOR method in the conventional oil industry. These heating systems are used to improve oil mobility near the wellbore by reducing viscosity and "to mitigate the risk of wax or hydrate formation in the production tube" [6]. While thermal treatment of oil shale represents a new application for these types of heaters, their costs are quantifiable and the performance of their components are well known, making them the best choice for the analysis in this report. Their use provides an "off-the-shelf" base case for the profitability analysis that follows.

Thermocouples are installed along the length of the heated section in order to monitor and to adjust temperature.

Simulations of the thermal treatment of a representative oil shale formation have been performed using STARS [7], a commercial reservoir simulation software package, in order to obtain production rates of oil and gas as a function of the time/temperature history of the formation. Details about the simulation and its results are given below, followed by a description of each of the in situ extraction process components, namely drilling wells, electrical resistance heating and electrical generators.

7.1.1.1 Simulation of In Situ Thermal Treatment Process

Regardless of the heating method selected, heating must take place for an extended period to heat the oil shale deposit to the target temperature for kerogen decomposition. A reaction scheme for kerogen decomposition, adapted from Braun and Burnham [8], is given below. The prolonged high temperatures that develop in the formation near the heating well produce an ever increasing fraction of CH_4 and other light gases as well as coke. The gases pressurize the deposit and help force the oil fractions to the production well; the coke remains in the deposit.

1. $Kerogen \rightarrow HO + LO + gas + CH_4 + char$
2. $HO \rightarrow LO + gas + CH_4 + char$
3. $LO \rightarrow gas + CH_4 + char$
4. $Gas \rightarrow CH_4 + char$
5. $Char \rightarrow CH_4 + gas + coke$

HO is heavy oil and LO is light oil.

To estimate heating profiles and production rates from a horizontal heater/producer well pair in the target formation at this in situ extraction site, a three-dimensional reservoir simulation of a 100 foot x 100 foot x 900 foot (30.5 meter x 30.5 meter x 274 meter) block in the target oil shale zone has been performed using the STARS thermal and process reservoir simulator [7]; STARS employs Darcy's law to compute fluid flow. There are 11 grid blocks in the x-direction, 20 grid blocks in the y-direction, and 21 grid blocks in the z-direction. The size of the grid blocks varies in the x-direction (along the length of the well) from 10 feet (3.04 meters) to 100 feet (30.5 meters); the grid blocks in the y- and z-direction are all five feet by five feet (1.52 meters). The heater well is located in the middle of the 100 foot x 100 foot (30.5 meter) reservoir cross-section; the heat flux from the heater well is set at 286 watts per foot (W/ft) (see Section 7.1.1.3). The producer well is located 50 feet (15.2 meters) directly below the heater at the edge of the computational domain. Two of the sides have a symmetry boundary condition, the two ends (at 0 and 900 feet) have a no flux boundary condition, and the top and bottom sides are impermeable to fluid flow but have a heat loss model applied that estimates heat loss to over/underburden. The semi-analytical heat loss model computes "heat transfer to or from an adjacent formation of infinite extent" [9]. Heat transfer occurs via conduction and via "convective" fluid flow as computed by Darcy's law.

Darcy's law for fluid flow in porous media assumes a linear relationship between the volumetric flow rate of the fluid and the pressure gradient. It is a diffusive relationship, so convective fluid flow and heat transfer are not well represented by Darcy's law. As fractures develop in the heated oil shale, convective heat transfer will occur that is not captured by the results presented here.

A symmetry boundary condition represents what might happen if the adjacent block were being heated simultaneously.

Rock and fluid properties (thermal, chemical, geomechanical, and geological) used in the simulation have been obtained from a variety of sources [10-13]. Porosity and permeability have been determined by the assumed richness of the oil shale (25 GPT). The heater well is specified with a constant heat flux of 2.108×10^7 Btu per day. This heat flux is distributed uniformly over the total length of the well (e.g. uniform per-length heating rate). The initial temperature of the formation is assumed to be 80°F (27°C), the pressure

Oil shale has poor heat transfer properties (e.g. low thermal conductivity), so conductive heating is very slow.

is assumed to be 1000 psi (6,895 kilopascals or kPa), and the initial solid (e.g. kerogen) concentration is specified to nearly fill the entire pore space with kerogen. Oil and gas production rates are computed using the reaction mechanism shown above.

The assumption of nearly filling the pore space with kerogen is equivalent to a 25 GPT oil shale.

Simulations have been run assuming both low (1 mD) and high (20 mD) initial fluid permeabilities. The low permeability case represents a typical, unfractured oil shale sample. The high permeability case represents a more optimistic scenario where the permeability of the rock has been enhanced through fracturing, rubblization, etc. Fluid permeability also increases as kerogen is heated and is converted to fluids (gas and liquid). For the base case profitability analysis in this report, the production curves from the high permeability case are used.

Figure 7.4 shows the transient temperature profile of the grid block that contains the heating source for the high initial permeability case. The simulation run time is extended to 30 years (six years beyond the 24-year project timeline) in order to capture peak production rates. After 30 years (10,957 days), temperatures are still rising slowly. For comparison, the target temperature range in the Shell ICP retort was 650°–700°F (343°–371°C). The temperatures in this block are considerably higher, favoring gas/coke rather than oil formation and the possible decomposition of dolomitic carbonate minerals. However, the temperature drops rapidly in blocks farther away from the heating well as shown in Figure 7.5.

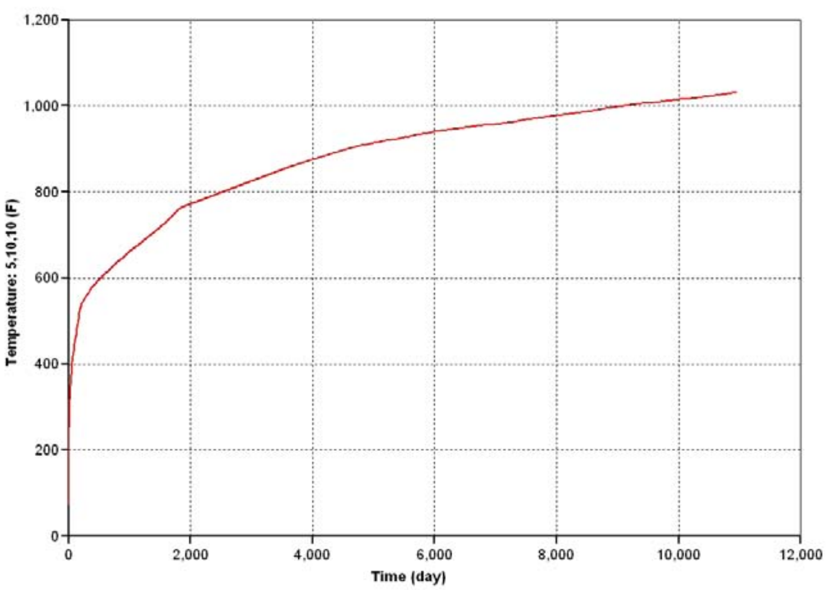
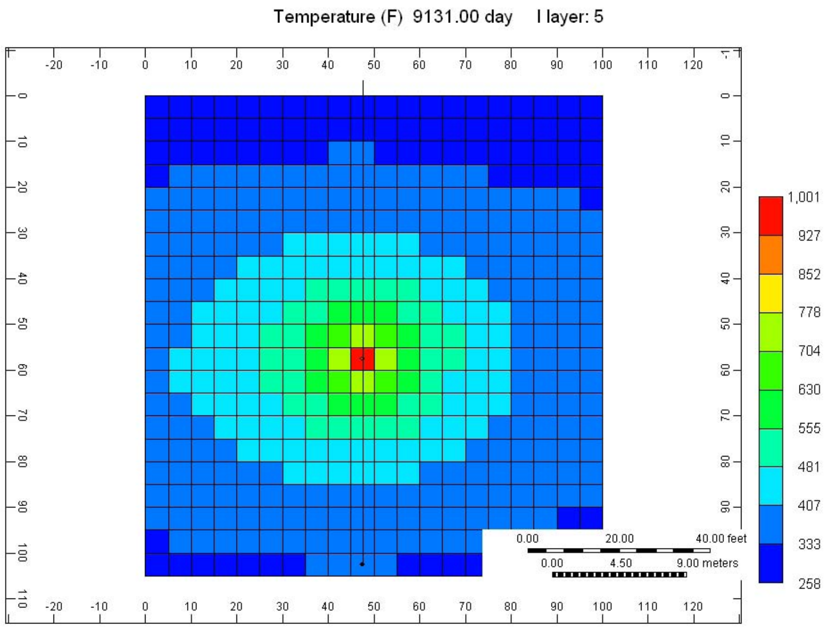


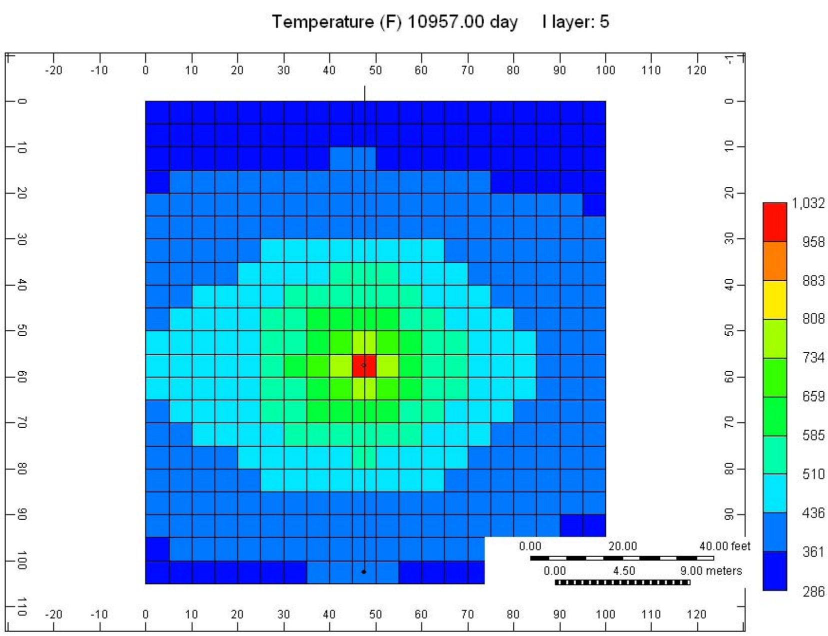
Figure 7.4: Temperature history of the grid block containing the heater well for the high initial permeability case. Figure courtesy of Jacob Bauman, University of Utah.

The "5,10,10" label on the y-axis indicates the location of the block.

Figure 7.5 shows the predicted temperature profiles in a cross section of the computational domain after 9,131 and 10,957 days (25 and 30 years). Figure 7.6 shows the corresponding kerogen conversion in the deposit. Very little kerogen decomposition occurs below 410°F (210°C).



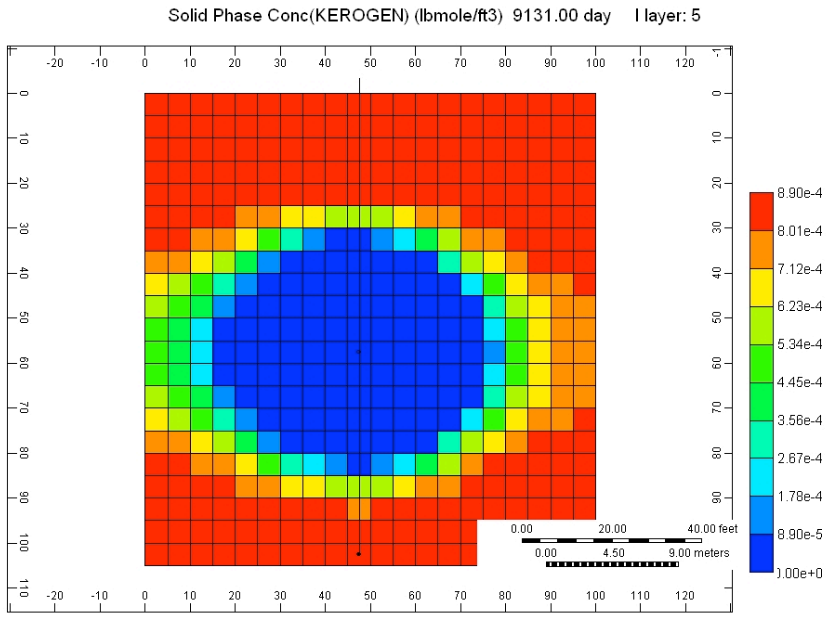
(a)



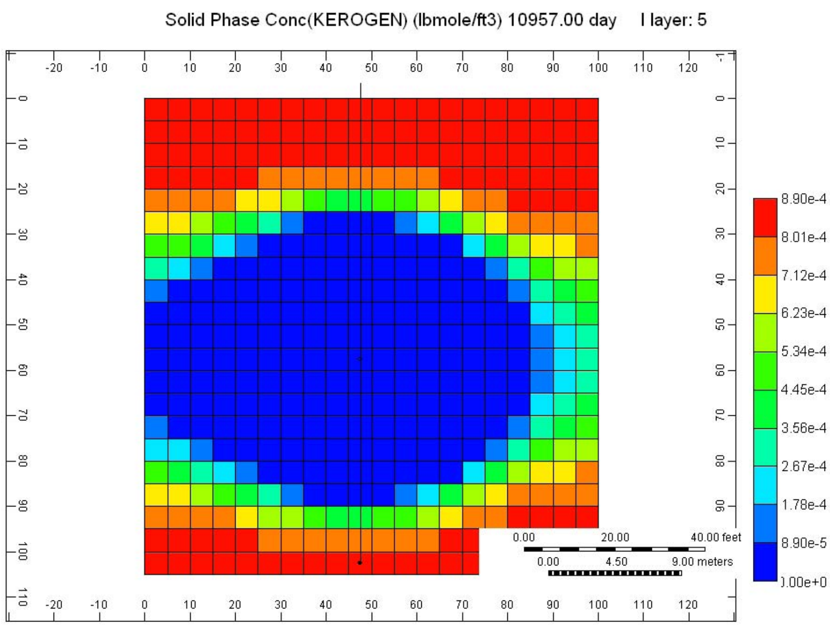
The heater well is represented by the black dot in the center of the figure and the producer well is the black dot at center bottom of the figure.

(b)

Figure 7.5: Temperature profile in the oil shale deposit perpendicular to the heater and producer wells after (a) 9,131 days days (25 years) and (b) 10,957 days (30 years) of heating for high initial permeability case. Figure courtesy of Jacob Bauman, University of Utah.



(a)



The blue areas in the cross section have been depleted of kerogen.

(b)

Figure 7.6: Kerogen conversion in the oil shale deposit perpendicular to the heater and producer wells after (a) 9,131 days days (25 years) and (b) 10,957 days (30 years) of heating for high initial permeability case. Figure courtesy of Jacob Bauman, University of Utah.

Cumulative totals for the high initial permeability simulation after 8,310 days (22 years, 9 months) of heating are given in Table 7-1 on a per foot basis. These totals would only apply to the first wells that were drilled; see the project schedule in Section 5.2.1.

The maximum possible heating time given this scenario's 24-year time line with one year for planning and three months for drilling/completion of the first wells is 22 years and 9 months.

Table 7-1. Cumulative production and heat required after 8,310 days (22 years, 9 months) of heating for high initial permeability case.

	Value	Units
Oil Produced	73.16	bbl/ft
Gas Produced	39,486	SCF/ft
Heat Required	1.95×10^8	Btu/ft

At the simulated reservoir conditions, the mass fraction of kerogen converted to oil is approximately 81% and to gas is approximately 10%.

All units are given on a per foot (/ft) basis.

Oil and gas production rates for the cumulative 900 feet (274 meters) of horizontal well length in the simulation are shown in Figures 7.7 and 7.8, respectively, for the high initial permeability case. Some gas production is realized within the first month of heating, but oil production is not consistently measurable until year three. After 23 years (8,400 days) of heating, the oil production rate from this single 900-foot well is approximately 23 BPD while the gas production rate is approximately 8,700 SCF per day. The maximum per well oil production rate of 27 BPD is reached after 27 years of heating, which is four years after the end of the project period for the first wells drilled. The gas production rate from this well is still rising after 30 years of heating. Peak gas production of 18,411 SCF per day is not reached until year 65.

After the 23-year heating period for the first wells drilled, less than 34% of the kerogen in the oil shale has been converted to oil, gas, and coke.

For this scenario, the horizontal length of the heater well is 4,366 feet (1331 meters); see Section 7.1.1.2. To compute the per well production rates of oil and gas for the "scenario well" based on the results from the "simulation well," the daily production rates from the simulation are divided by the 900-foot (274-meter) well length to obtain per foot production rates. The per foot production rate multiplied by the length of the horizontal section of the "scenario well" (4,366 feet or 1331 meters) gives the desired per well production rates of oil and gas. Using this formula, the production from a "scenario well" after 23 years of heating is 112 BPD.

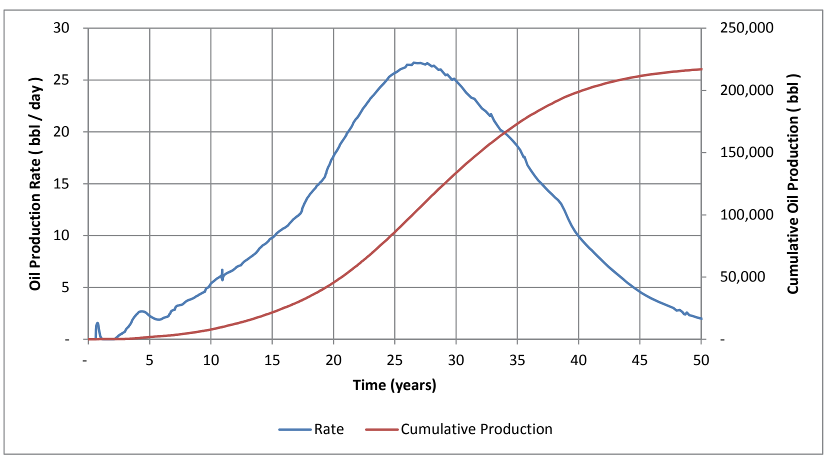


Figure 7.7: Oil production rate and cumulative oil production results from simulation of 900-foot (274-meter) long well with high initial permeability. Figure courtesy of Jacob Bauman, University of Utah.

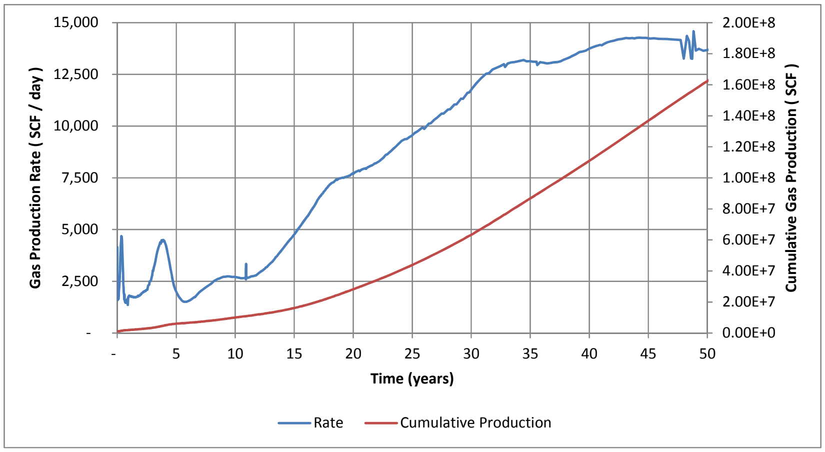


Figure 7.8: Gas production rate and cumulative gas production results from simulation of 900-foot (274-meter) long well with high initial permeability. Figure courtesy of Jacob Bauman, University of Utah.

The higher frequency fluctuations in the oil and gas production rates are due to numerical instability.

As indicated by Figures 7.7 and 7.8, further heating of the deposit would yield high production levels of oil and gas for a significant period of time beyond the 24-year project lifetime analyzed in this report, further reducing the cost per barrel for the project. However, in order to maintain the same baseline for comparing with the other scenarios in this report, only production through year 24 is considered in the subsequent "base case" analysis. The impact of continued heating is partially considered in the accelerated heating schedule case of the sensitivity study (Section 7.3.4), which assumes that production begins immediately at year eight levels. Cutting out the first seven years of the production curve shifts the endpoint from year 23 to year 30 for the wells drilled in the earliest year (year two) of the project.

With the accelerated production schedule, a well that had been heated for one year would produce oil and gas as if it had been heated for eight years. The net effect is that fewer wells are required (960 wells in the base case versus 664 wells in the accelerated case) to meet the goal of 50,000 BPD of production by 2035.

Total raw shale oil production in year 24 of the project is 42,228 BPD, which, after upgrading, results in a nominal production rate of 50,000 BPD of SCO. Based on the oil production rate shown in Figure 7.7, the "average" daily production of SCO over the 23-year heating period of the project is 15,134 BPD. Maximum total raw shale oil production of 61,268 BPD is reached in year 42, the year in which wells drilled in the fourth year of drilling (2016) have reached peak production (27 years of heating).

Gas and oil production curves for the low initial permeability case are shown in Figures 7.9 and 7.10, respectively; the well is 900 feet (274 meters) long. The strong effect of initial permeability on oil production rates and cumulative oil production can be seen by comparing Figures 7.7 and 7.9. The low initial permeability case does not show measurable oil production until year four and production rates peak after 33 years of heating compared with 27 years for the high initial permeability case. Production rates for the high initial permeability case are approximately 2 BPD greater than those for the low initial permeability case at equivalent heating times up to 15 years. In the second half of the heating period, production rates in the high permeability case increase faster than in the low permeability case, resulting in production rates that are 5–10 BPD greater. The result is that peak oil production rate for the high permeability case is 27 BPD while for the low permeability case, it is 20 BPD. Conversely, the effect of initial permeability on gas production is not very pronounced. Both Figures 7.8 and 7.10 exhibit similar trends and magnitudes for production rate and cumulative production with respect to heating time.

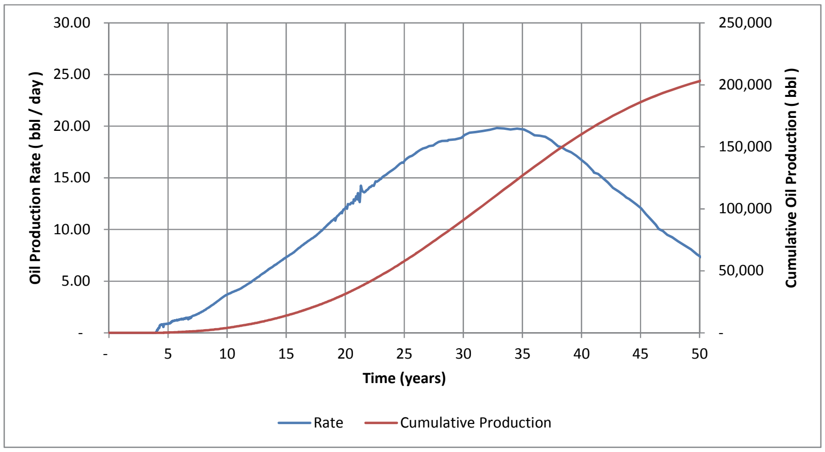


Figure 7.9: Oil production rate and cumulative oil production results from simulation of 900-foot (274-meter) long well with low initial permeability. Figure courtesy of Jacob Bauman, University of Utah.

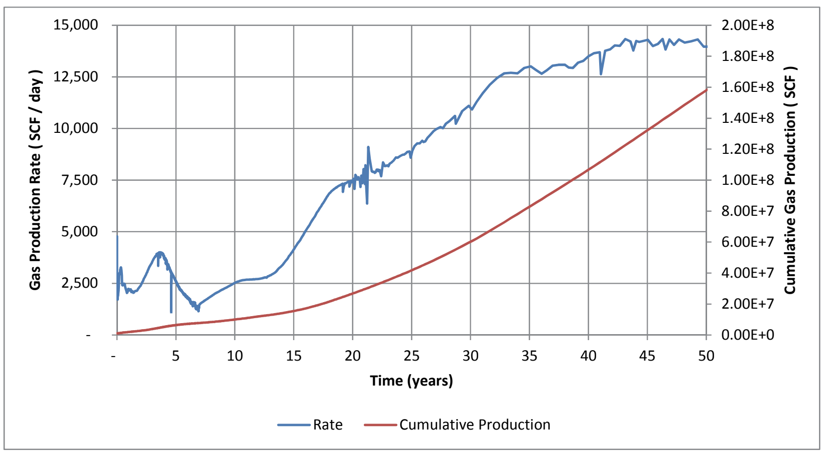


Figure 7.10: Gas production rate and cumulative gas production results from simulation of 900-foot (274-meter) long well with low initial permeability. Figure courtesy of Jacob Bauman, University of Utah.

7.1.1.2 Drilling Horizontal Wells

Horizontally-drilled wells are preferable to other drilling patterns for accessing oil shale in the Uinta Basin because the target oil shale deposit is relatively thin (approximately 100 feet or 30.5 meters thick) compared to the amount of overburden (approximately 1,000 feet or 305 meters) that must be drilled through to access the deposit. Therefore, for this scenario, the well design illustrated in Figure 7.11 is assumed. The design involves two horizontal wells drilled in the oil shale deposit with a heating well running through the middle of the formation and a production well located near the bottom. A second pair of wells is drilled from the same well pad, oriented 180° and 100 feet (30.5 meters) away from the first pair (collectively referred to hereafter as a "well set"). Assuming a 100-foot (30.5 meter) thick deposit with 1,000 feet (305 meters) of overburden, the vertical depth of the heating and production wells are 1,050 feet (320 meters) and 1,100 feet (335 meters), respectively. The drilling of the well pair requires precise directional control, something that can be achieved with all of the drilling rigs currently in use in the Uinta Basin [14].

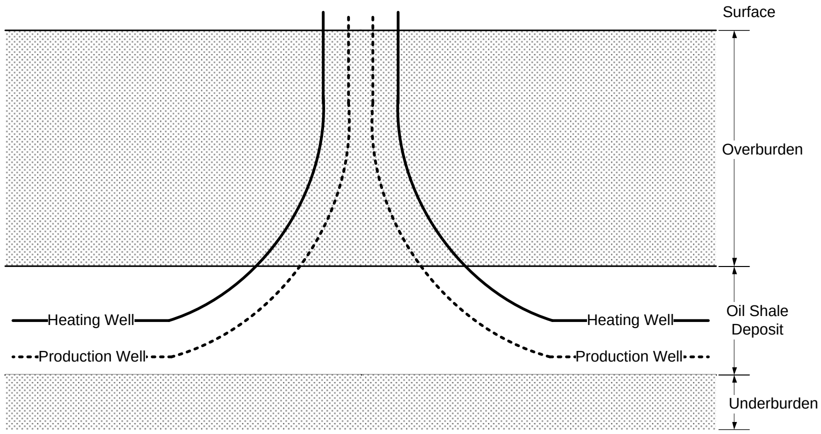


Figure 7.11: Conceptual diagram of horizontal wells drilled for in situ extraction of oil shale.

The dimensions of the various segments of the well are summarized in Table 7-2. This well geometry is based on the maximum length available from the manufacturer for a downhole heating element [6], the depth of the target oil shale formation, and the turn radius that can be accomplished with 30-foot (9.1 meter) pipe sections. The well pair is relatively shallow, but the horizontal sections of the heater and producer extend for 4,366 feet (1,331 meters).

Table 7-2. Well geometry.

Pipe Segment	Heater	Producer	Notes
Vertical (ft)	482	532	Producer has longer vertical segment so that lateral section is located 50-ft (15.2-m) below heater
Turn (ft)	892	892	Buildup rate of 3° per 30-ft (9.1-m) pipe segment
Horizontal (ft)	4,366	4,366	Set so that total length equals maximum length of heat tracing line
Total (ft)	5,740	5,790	Measured depth from surface to end of lateral

The assumed turn radius is 3° per 30-foot pipe section.

m = meters

The total number of well sets (2 heating and 2 production wells) that needs to be drilled is 240 for the base case and 352 for the low initial permeability case. These totals were determined based on the following inputs/constraints:

- Constraint on total well length due to the downhole heating element
- Oil production curves obtained from the simulation presented in the previous section
- Construction/drilling/heating timeline presented in Section 5.2.1
- Production requirements for the project.

The well sets are spaced 100 feet (30.5 meters) apart, an assumption made for the reservoir simulations discussed in Section 7.1.1.1. In documents published by Shell related to their ICP technology [4], well spacing did not exceed 42 feet (12.8 meters), leading to an overlap in heating zones between wells that this scenario does not have.

In this analysis, 30 well pairs (60 wells) are drilled each quarter beginning in year two and ending in year five (i.e. all wells are completed in four years). The drilling time for one well is 10–15 days [14], so a single drilling rig can drill one well pair per month. This level of drilling will require 15 drill rigs (22 drill rigs for the low permeability case) for the 4-year duration of the drilling phase of the project. For comparison, there are currently 16 rigs drilling in the Uinta Basin [14].

A total of 960 wells are drilled for the base case while 664 wells are drilled for the accelerated production case.

Drilling of the well is followed by completion, the process of preparing a drilled well for heating or production [15]. Casing must be installed in both the heater and producer wells, the producer well must be perforated so that produced raw shale oil can flow into it, and some type of fracturing may be performed. Additionally, the downhole heaters must be inserted into the heater wells (see Section 7.1.1.3) and final testing/preparation completed. The assumption for this scenario is that the total time to drill and complete the well set (four horizontal wells) at each well pad is three months. This assumption is based on DOGM data for three horizontal wells drilled in the Uinta Basin since 2008. Total time to make the wells averaged about 70 working days; calendar time from the start of site preparation through well completion was almost three months [16].

Steel casing is used to line the drill hole and is typically cemented in place.

Per well costs for drilling and completion are assumed to be $3.0 million ($2.0 million for drilling and $1.0 million for completion). This cost is at the low end of the potential cost range as determined from various sources. An industry consultant in the Uinta Basin, William Ryan, stated that a reasonable assumption of drilling costs for the type and length of wells proposed for this scenario is $3.5–$5 million per well [14]. According to Mr. Ryan, if 15 or more drilling rigs were drilling in the same general area all year long, drilling costs could be tightened up to about $2.0 million per well. A second source of data is a 2000-foot (610-meter) long, directionally-drilled oil shale well with a 12 inch (30.5-centimeter) diameter that was recently estimated to cost $2.5 million. A third source of data is the DOGM database of oil and gas wells [16]. There are three entries in the DOGM database, summarized in Table 7-3, with fully disclosed cost data for horizontal wells drilled in the Uinta Basin since 2008. These data could not extrapolated to the well depths needed for this report because the variation in depth among the three is not large enough and the impact on cost of well diameter is not clear.

This per well cost is assumed to include all costs associated with drilling/completion, including labor costs.

Completion costs are in addition to the drilling costs quoted here.

The operator most involved in horizontal drilling discloses completion costs but not drilling costs.

Table 7-3. Drilling and completion costs in US$ for horizontal gas wells drilled in the Uinta Basin.

Completion Date	Drilling Cost	Completion Cost	Total Well Cost	Measured Depth (ft)	Vertical Depth (ft)
2010	$3,211,991	$1,546,616	$4,758,607	11,355	7,182
2008	$2,929,300	$2,424,886	$5,354,186	11,710	8,062
2008	$3,087,745	$3,449,269	$6,537,014	11,159	77,447

"Measured depth" is the length of a taut string running from the initial to the terminal point of the well. "Vertical depth" is the length of the shortest line from the terminal point of the well to the surface of the earth.

7.1.1.3 Heat Tracing for Electrical Resistance Heating of Heater Wells

Downhole heating is provided by a heat tracing line that converts electricity generated at the surface into heat in the lateral segment of each heating well; conductive heat transfer into the oil shale deposit occurs through the wall of the drill casing with some heat lost to formations both above and below the target heating zone. The design and costing of the heat tracing system is based on a case study using a Tyco mineral insulated (MI) electric heat tracing line (see Figure 7.12) in California heavy oil wells [17]. Specifically, the constant heat flux boundary condition for the heating wells in the simulations described in Section 7.1.1.1 was set to 286 W/ft based on the heat flux reported in Tyco's case study. Other characteristics and design of the heat tracing line are summarized in Table 7-4.

Figure 7.12: Tyco MI electric heat tracing line, consisting of two conductors insulated by magnesium oxide and enclosed in a metal sheath; from McQueen et al. [17].

Table 7-4. Characteristics of MI heat tracing line.

Characteristic	Value	Notes
Maximum constant temperature	1022°F (550°C)	
Maximum heat output	82 W/ft (269 W/m)	Per line
Maximum length	5,740 ft (1,750 m)	
Case study system length	1,936 ft (590 m)	
Case study system cost	$94,346	Adjusted to 2012 US$ using CEPCI index
Design heat flux	286 W/ft (938 W/m)	Same heat flux achieved in case study [17] with six passes of heat tracing line [17]
Design length	4,366 ft (1,331 m)	
Design cost	$181,105	Per heating well, 2012 US$

W/m = Watts per meter

7.1.1.4 Natural Gas-Fired Generators for Supplying Electricity to Heat Tracing Lines

The electricity required for heat tracing is provided by a modular generator unit positioned at each well pad. This decentralized electrical generation system was selected to avoid regulatory hurdles associated with building a large power plant. Given the design length and heat flux of the heat tracing system, each well set requires 2.5 megawatts (MW) of electrical generation capacity. A reciprocating natural-gas fired generator produces electricity for each well set. The design and costing of the generator system, summarized below in Table 7-5, is based on general information provided by Wärtsilä

The total generation capacity needed for all 240 well pads in the base case is 599 MW and for all 352 well pads in the low initial permeability case is 879 MW.

North America for their modular, single-engine power plants. Each unit is a "fully functional power plant with all the auxiliaries and components that a power production unit requires" [19].

An added benefit is that these reciprocating engine generators tend to have higher efficiencies than gas turbines.

Table 7-5. Wärtsilä electrical generator system (per unit) [19,20].

g/hp-hr = grams per horsepower per hour.

Generator technology	Reciprocating gas-fired engine
Electrical efficiency	46%
Natural gas usage	445 MMBtu/day
Maximum electrical power output	9 MW
Design electrical power output	2.5 MW
Cost rate[a]	\$1,100/kW
Capital cost	\$2.75 million
NO_x emissions rate	0.5 g/hp-hr
Annual NO_x emissions	16.2 ton/year
Installation time	9 months - 1 year

[a]*Mid point of cost range quoted by Wärtsilä*

Several operational issues should be noted for this electrical generation system design. First, because the system is decentralized, oxy-firing and CO_2 capture are more difficult to implement then they would be for a centralized system. As a result, the generator system is excluded from the oxy-firing system in this analysis. Second, this analysis assumes that any gas produced by in situ heating of oil shale is used in the generator system. However, in reality, produced gas would contain higher molecular weight hydrocarbons such as ethane, propane, and butane. These gases are not only more valuable as a chemical feedstock than as a fuel, but they also burn at temperatures beyond the operational range of the reciprocating engine generators. Produced gases would therefore be more useful as a product that could be sold to a gas company in exchange for fuel. Finally, while reciprocating engines operate at higher efficiency than gas turbines, they also require more maintenance.

For the purposes of this analysis, the produced gas is assumed to be pure methane.

7.1.1.5 Other In Situ Production Costs

In situ production of oil shale will require piping, pumps, surge/storage tanks, gas/oil separation, produced gas treatment [20], and other ancillary units that are not included in this cost analysis due to lack of cost and design information. It is anticipated that these costs will be small compared with the costs of electrical heating and drilling/completion of wells.

7.1.2 Oil Production Prior to Construction of Upgrader

A small amount of oil is produced prior to the completion of upgrading facilities and pipeline routes. This oil is assumed to be transported by truck from the wellhead to refiners at a cost of $5.22/bbl. Transportation costs are estimated from [21] by scaling from 2007 US$ to 2012 US$ using an inflation rate of 1.8%. The oil is sold "as is" at a price equivalent to Uinta Basin black wax crude, which is approximately $13.00/bbl less than WTI [22].

On average, 30 BPD is produced in 2013 with production increasing to an average of 308 BPD in 2015. Total oil production over the three-year construction period is 238,159 barrels.

7.1.3 Fractionation

The fractionator is an atmospheric distillation column that separates produced raw shale oil into the following streams:

- Gases
- Fouled water
- Naptha - hydrocarbons with a boiling range of 1100°–400°F (38°–204°C)
- VGO - hydrocarbons with a boiling range of 400°–950°F (204°–510°C)

The distillation column produces fouled water from steam stripping.

However, the produced oil arriving at the fractionator in this scenario has been stripped of produced gas and contains no heavy fractions (e.g. wax) due to the high quality product obtained from in situ retorting [20,23]. Thus, only the naptha and VGO distillation cuts comprise the shale oil product from the in situ production process. These distillation cuts are stored in heated surge tanks until they are moved to the hydrotreater for upgrading. Capital and operating costs for the fractionator are scaled from data given by Maples [24].

Other feed pretreatment steps such as olefin and metal removal are not considered in this analysis.

7.1.4 Primary Upgrading

Shale oil produced in situ has a high API and does not require primary upgrading for molecular weight reduction.

7.1.5 Secondary Upgrading

Due to the effect of heating rate on oil quality, raw shale oil produced in situ does not require the same extent of secondary upgrading as raw shale oil produced from an ex situ retort. It is more paraffinic and less aromatic then surface retort-produced shale oils [25]. Beer et al. [23] report an API gravity of 20° for a raw shale oil produced at a surface-retort heating rate of 10,000°C/day while the API gravity of shale oil produced at in-situ (e.g. ICP) heating rates (0.5°–3°C/day) is in the 35°–40° range [4]. Hence, secondary upgrading is not needed to convert the aromatic components to paraffins but only to remove the nitrogen, sulfur, and heavy metal content of the raw shale oil. As a result, the H_2 requirement is lower than that for the ex situ oil shale scenario.

Paraffins consist of single-bonded carbon and hydrogen atoms. In aromatic compounds, the carbons are bound together in a cyclic structure with alternating double and single bonds.

The Shell ICP shale oil product is approximately 28 wt% naptha, 28 wt% jet fuel, 28 wt% diesel, and 16 wt% bottoms (e.g. boiling point greater than 650°F or 343°C) [4].

The upgrading process takes place in catalytic reactors known as hydrotreaters (one for each distillate cut) where H_2 is reacted with the raw shale oil; see Figure 6.8. The process conditions, catalysts, and design/costing methodologies are the same as those for the ex situ oil shale scenario, but the sizes of the various unit operations are smaller as less H_2 addition is required. The H_2 input to the hydrotreater is provided by the hydrogen plant shown in Figure 6.9.

Due to lack of available data, hydrotreating for heavy metal removal is not considered in this analysis.

Very little data is available concerning the quantity of H_2 required to achieve a given improvement in the quality of shale oil produced in situ [4,20,23]. This analysis assumes that the H_2 requirement is simply what would be necessary (as calculated by reaction stoichiometry) to reduce the sulfur and nitrogen content of the raw shale oil to a refinery ready feedstock (0.01 wt% sulfur and 0.10 wt% nitrogen). All other properties of the shale oil before and after hydrotreating are assumed to be the same; see Table 7-6.

Annual production of the gaseous byproducts of hydrotreating is similar to that for the ex situ oil shale scenario: 21,300 tons (19,300 metric tons) of H_2S and 22,700 tons (20,600 metric tons) of NH_3.

Table 7-6. Properties of raw and upgraded shale oil [20,26] in comparison to three benchmark crudes [27,28].

		Raw Shale Oil	Upgraded Shale Oil	West Texas Intermediate	Brent Crude	Arabian Light Crude
Oil Properties	API Gravity	35	35	39.6	38	34
	Sulfur (wt%)	0.8	0.01	0.24	0.37	1.7
	Nitrogen (wt%)	1	0.1		0.1	0.07
	Pour Point (°F)		0	-18	45	-10
	Solids (wt%)	0				
Distillate Cuts	Boiling Range (°F)	(vol %)				
Naptha	100 - 400	44.5	44.5	56		
	104 - 800				78	67
Vacuum Gas Oil	400 - 950	55.5	55.5	32		
	800 +				21.7	32
Wax	950 +	0	0	9		
	1000 +				10.2	17

7.1.6 Hydrogen Plant

Based on the mass of sulfur and nitrogen to be removed, the H_2 requirement for this in situ extraction process is 129 SCF (3.65 cubic meters) of H_2 per barrel of raw shale oil, which is 1,871 SCF (53.0 cubic meters) less than the H_2 requirement for upgrading one barrel of ex situ shale oil. This methodology is likely underestimating the amount of H_2 required (see Section 7.1.5), but the total will still be much less than for ex situ shale oil.

The sulfur content of the raw shale is reduced by 0.79 wt% while its nitrogen content is reduced by 0.9 wt%; see Table 7-6.

The H_2 will be supplied by a hydrogen plant of the same PSA-based design discussed in section 6.1.7. However, the size of the plant will be much smaller for this scenario due to the lower H_2 demand of the raw shale oil. The plant will be located in Bonanza, Utah, adjacent to the hydrotreater. The H_2 that is produced will be used solely for upgrading of the raw shale oil.

Using the economic and engineering scaling factors discussed in Section 5, the capital and operating costs for the hydrogen plant are determined using capital and utilities utilization data from Fleshman [29]. The excess steam produced by the plant is taken as a credit rather than utilizing it elsewhere in the production/upgrading process. The credit is taken in the form of a sale of steam back to the off-site steam utility at 50% of the cost of purchasing high pressure (600 psig, 700°F) steam.

At full production (50,000 BPD), which is only reached at the end of the project period, the in situ oil shale production/upgrading process requires 4.9 billion pounds (2.2 billion kilograms) of steam and produces 0.5 billion pounds (0.23 billion kilograms) of steam per year.

7.1.7 Ammonia Scrubber

Sour gases generated as byproducts in the hydrotreater are fed to a wet scrubber with dilute sulfuric acid to remove NH_3 as described in Section 6.1.8. Capital and operating expenses as well as ammonium sulfate sales are neglected in the cash flow analysis. Ammonium sulfate production is estimated to be 88,000 tons (79,800 metric tons) annually.

7.1.8 Amine Treatment Unit

The amine treatment unit scrubs acid gas, e.g. H_2S, from the waste gas streams as described in Section 6.1.9. Capital and operating costs are scaled from data in Maples [24]. See Figure 7.3 for an overview of how this unit is integrated with the ammonia scrubber, sulfur recovery unit and sour water stripper.

7.1.9 Sulfur Recovery Unit

Acid gas streams are further stripped of H_2S in the sulfur recovery unit as described in Section 6.1.10. The product, elemental sulfur, is produced at a rate of 19,000 tons (17,300 metric tons) annually. Elemental sulfur is the product. Capital and operating costs are scaled from data in Maples [24], a sulfur recovery rate of 95% is assumed, and all sulfur recovered is sold at market prices [30].

7.1.10 Sour Water Stripper

Fouled water from the fractionator and recycled cooling water from the hydrotreater (see Figure 7.3) is processed through a sour water stripper to remove dissolved contaminants as described in Section 6.1.11. The stripped water is then sent to the water reservoir (see Section 7.2.3) for reuse. Capital and operating costs are scaled from data in Maples [24].

7.1.11 Transportation via Pipeline

The upgraded shale oil is taken from storage tanks at the upgrader and sent through a pipeline from Bonanza, Utah, to North Salt Lake City. The pipeline path is shown in Figure 6.10. The total estimated pipeline length is 159 miles (256 kilometers).

An economical pipeline diameter of 9.1 inches (23.1 centimeters) was computed by optimizing the pumping requirements and costs using the method of Peters and Timmerhaus [31]. The capital costs for constructing the pipeline and pumping stations are estimated following the methodology used by Boyle [32]. Additional details about the pipeline are found in Section 6.1.12.

7.1.12 Cost of Utilities

The utilities required for the situ oil shale scenario are listed in Table 5-7: natural gas; electricity; process, cooling and boiler feed water; chemicals; steam; O_2; and refrigerant. With one exception, this scenario employs the constant utility prices in Table 5-7. The exception is the profitability analysis using the NPV method, which uses EIA price forecasts to estimate natural gas and electricity prices [33].

Natural gas and electricity are brought in to the site from the closest hubs, which are assumed to be located outside Bonanza, Utah, a distance of approximately 10.7 miles (17.2 kilometers). Water for plant needs is pumped 1.6 miles (2.6 kilometers) from the White River via pipeline to a reservoir at the plant site. Raw water from the reservoir (see Section 7.2.3) is treated such that it is suitable for use as process, cooling, and boiler feed water. The chemicals for water treatment and other purposes are trucked in and stored in a warehouse.

Electricity for downhole heating is generated on-site using modular units as described in Section 7.1.1.4. The electricity for all other plant processes is purchased from on off-site utility as described in this section.

Produced gas from in situ retorting is assumed to offset the purchased volume of natural gas. However, the costs of produced gas cleanup are not included in this analysis and it is likely that the gas would be sold as a feedstock rather than burned.

Three other required utilities, namely steam, refrigeration, and O_2 (for oxy-fired processes related to upgrading only), are purchased from off-site utility plants at the per unit cost given in Table 5-7. Other than capital costs for construction, these prices are assumed to cover all of the costs/externalities of the utilities. Capital costs for constructing the steam, water treatment and refrigeration plants are estimated from Seider et al. [34] and are listed in Table 5-5 under allocated costs for utility plants. Capital costs for the oxygen plant are excluded due to lack of data.

Infrastructure costs associated with bringing utilities to the site are accounted for in various ways. Costs associated with (1) building an electrical substation ($4.5 million), (2) establishing the electrical line, switching gear, and tap ($4.6 million), and (3) bringing in the natural gas line ($11.3 million) and establishing the metering hub ($1.0 million) have been obtained from Sage Geotech [35]. The costs of the water pipeline ($0.409 million) and the water reservoir ($0.921 million) have been estimated using standard construction and excavation cost estimation methods [32,36]. Warehousing costs of chemicals are accounted for in the percentage (10%) of C_{TBM} used for service facilities [34]; see Table 5-5.

Costs given here are for the air-fired case. For oxy-firing, the cost of the electrical substation increases to $6.2 million, the water pipeline to $0.414 million, and the water reservoir to $0.973 million.

7.1.13 Labor Utilization

Labor costs for skilled labor, maintenance labor, and management are included in this supply cost analysis. Skilled labor and management requirements are considered in this section while maintenance labor requirements are excluded. Instead, the costs of maintenance labor are assumed to be covered by the yearly maintenance cost (5% of C_{TDC}).

For each unit operation in the overall process with the exception of drilling, the number of employees on a per shift basis is determined. Assuming that five shifts per week are used for 24/7 operation, the total number of employees for this scenario is 325 as listed in Table 7-7; that number increases to 360 for the scenario variation with oxy-firing. Labor requirements for all unit operations are estimated following the approach given by Seider et al. [34], but uncertainty with the methodology means that actual labor requirements could be quite different from those predicted here.

Labor requirements for drilling are included in the per well cost estimate given in Section 7.1.1.2.

Table 7-7. Labor requirements for in situ oil shale extraction (per shift).

Process	Operators	Lab & Engineering	Management
In Situ Heating	4	2	1
Fractionator	2	2	1
Hydrotreater	18	2	1
H_2 Plant	6	2	1
Sour Water Stripper	4	2	1
Amine Treatment Unit	4	2	1
Sulfur Recovery Unit	6	2	1
Total	**44**	**14**	**7**
Oxy-Fired Only			
CO_2 Compressor	4	2	1
Total	**48**	**16**	**8**

These labor requirements are for the startup and production phases of the project and do not include labor required for construction of the various unit operations.

7.2 Environmental Aspects of In Situ Oil Shale Scenario

The profitability analysis for this scenario does not include the cost of externalities associated with visual impairment, effects on ground and surface water quality, the treatment/storage of waste effluents, the reallocation of land area for well pads/piping/upgrader/etc., or the roads required for access. This analysis does account for the costs of some air pollution control, reclamation, carbon management, and water management as described below.

7.2.1 Air Pollution Control

As outlined in Sections 7.1.8 and 7.1.9 above, this scenario includes the costs of removing H_2S from the various sour gas streams generated by shale oil upgrading. It does not include capital and operating expenses for removing NH_3, which are assumed to be offset by the sale of ammonium sulfate (see Section 7.1.7). As capital and operating costs for other air pollution control equipment are difficult to estimate, their costs are assumed to be covered by this scenario's contingency cost, which is $244 million.

7.2.2 Reclamation Costs

The 2008 RAND report [37], in noting the advantages of in situ over ex situ oil shale production states, "Reclamation costs, while not insignificant, should be lower because Shell's process involves much less land disturbance than mining and does not require disposal of spent shale." In a recent analysis of Wyoming data on the cost of reclaiming land disturbed by oil and gas development, the authors report that the actual cost of full reclamation of 255 orphaned wells was approximately $29,600 per well (inflated from 2008 to 2012 US$ using a 1.8% inflation rate) [38]. Based on the number of wells drilled for this scenario (960), the cost of reclamation is $28.4 million. This cost can be compared to operating expenses of $24 million per year for spent shale disposal and reclamation assumed for the ex situ oil shale scenario.

7.2.3 Carbon Management

As with the ex situ oil shale scenario, two different combustion systems are used to supply heat to the various unit operations involved in upgrading. In the conventional (air-fired) system, there is no CO_2 capture; exhaust gases are sent to the stack. Two cases are considered for the supply cost analysis: (1) no tax on CO_2 and (2) a $25 per ton tax on CO_2. In the oxy-combustion system, product gases are treated in the cryogenic system described in Section 6.2.3 to produce a nearly pure CO_2 stream that is compressed to pipeline conditions and sold at a price of $25 per ton.

The various costing methods used for the unit operations in the carbon management system are described in Section 6.2.3. The cost of the combustion system is computed in ProMax and then rolled into the cost reported for the hydrotreater. The costs for the gas cleanup system are described in Sections 7.1.8 and 7.1.9. A regression fit to Promax results at various scales is used to cost the CO_2 compression system. The O_2 required for oxy-firing is purchased from a supplier at the price per ton listed in Table 5-7. The costs of a CO_2 pipeline are assumed to be the responsibility of the purchaser and are not included in the present analysis.

For additional information about the CO_2 compression and cleanup plant, see Castro [39].

For the scenarios, GHG emissions, including CO_2, CH_4, and N_2O, are produced from: electricity generation associated with the in situ thermal treatment process, the fractionator, the hydrogen plant, and the hydrotreater; well drilling; off-site steam and electricity generation, including that required for the air separation unit that supplies the O_2 for oxy-firing; and product transport to the refinery. Total CO_2e emissions from these sources are 3.693 million tons (3.350 million metric tons) per year for the accelerated-heating case and 3.471 million tons (3.148 million metric tons) per year for the base case. For the oxy-fired base case, total production of pipelineable-quality CO_2 from the fractionator, the hydrogen plant, and the hydrotreater is 0.540 million tons (0.490 million metric tons) per year while 2.990 million tons (2.712 million metric tons) CO_2e are emitted. The CO_2 emissions from the electrical generators are not captured in the oxy-fired scenario since no information on oxy-fired electrical generators was available from the manufacturer. All totals neglect GHG emissions associated with construction of the facilities, refrigeration, water treatment and in situ decomposition of carbonate minerals (dolomite and calcite) in the oil shale. Some carbonate decomposition may occur in the volume of shale proximal to the heater well as predicted temperatures are slightly above 1000°F (538°C), but based on the simulation results (see Figure 7.5), this decomposition is confined to a relatively small volume.

Decomposition of dolomite and calcite occurs at 1112°F (600°C) and above.

A more detailed analysis of CO_2 emissions from shale oil production using the Shell ICP process was conducted by Brandt [25]. Brandt reports WTP GHG emissions of 38–63 g CO_2e/MJ compared to the estimate of 88 g CO_2e/MJ obtained using CO_2 emissions projected for this scenario and adding emissions from refining [40]. Likely sources of this discrepancy include differences in the heating well layout and assumptions about the properties of the rock. For example, the Brandt paper uses data from Shell's permitting documentation as the basis its analysis of CO_2 emissions from the production phase. This scenario employs a different well spacing and uses the STARS reservoir simulation tool to predict shale oil production curves as a function of heating time. Also, permeability and porosity are not discussed in the Brandt paper. In this work, the production curves obtained from the STARS simulations are very sensitive to permeability and porosity inputs. Porosity is related to shale grade, so this analysis uses a porosity of 30.1% to match a Fischer Assay of 25 GPT (assuming the porous space is initially filled with kerogen). Changes in the production curve for the same amount of heat input will strongly affect CO_2 emissions per energy unit of fuel.

Of the 88 g CO_2e/MJ estimate for this scenario, the natural gas-fired well heaters account for 68 g CO_2e/MJ.

7.2.4 Water Management

In situ oil shale production has the same three-part water balance as the ex situ oil shale scenario: processes that generate, consume, and recycle water as shown in Figure 6.12. Itemized water balances for the air- and oxy-fired in situ oil shale scenarios are shown in Table 7-8 on both a per barrel and annual water usage basis. At full production (50,000 BPD), the total required makeup water for the air-fired case is 649 acre-feet per year (0.896 CFS or 0.0254 CMS). The total for the oxy-fired case is 664 acre-feet per year (0.917 CFS or 0.0260 CMS) due to the larger cooling water demand for the CO_2 compressor system which leads to increased recycle losses. However, since the amount of oil produced slowly increases over time, reaching full production only after 24 years, the average production rate over the life of the project is only 15,134 BPD. Excluding water for drilling, the corresponding average water usage over the life of the project is 63 acre-feet per year (0.0866 CFS or 0.0025 CMS) for the air-fired scenario and 67 acre-feet per year (0.0927 CFS or 0.0026 CMS) for oxy-fired scenario.

Table 7-8. Itemized water balance for in situ oil shale production with air- and oxy-firing at full production (50,000 BPD); data obtained from various sources [24,29,41,42] and from Promax simulations.

This table does not include water needed for reclamation.

Category	Item	Water (bbl / bbl of oil)		Water (acre-ft/yr)	
		Air-Fired	Oxy-Fired		
Recycled	Cooling Water				
	Hydrotreater	0.13	0.13	298	298
	H_2 Plant	0.15	0.15	351	351
	CO_2 Compressor	-	4.82	-	11,346
	Sulfur Recovery Unit	0.11	0.11	261	261
	Boiler Feed Water				
	Sulfur Recovery Unit	0.02	0.02	39	39
	Steam	0.76	0.76	1,790	1,790
	Subtotal	**1.16**	**5.99**	**2,739**	**14,085**
Consumed	H_2 Plant	0.05	0.05	125	125
	Drilling	0.65	0.65	442	442
	Upgrading				
	Cooling Tower Makeup	0.01	0.16	28	369
	Steam Recycle Losses	0.02	0.02	54	54
	Subtotal	**0.74**	**0.88**	**649**	**989**
Generated	CO_2 Compressor	-	0.14	-	326
	Subtotal	**-**	**0.14**	**-**	**326**
Water In		**0.74**	**0.74**	**649**	**664**

In a recent GAO report, water for reclamation activities represented the largest water consumer and the largest source of uncertainty for in situ oil operations [43]. The report states that the "large range is due primarily to the uncertainty in how much rinsing of retorted zones would be necessary to remove residual hydrocarbons and return groundwater to its original quality." However, groundwater aquifers are not co-located with the rich oil shale zones proposed for development under this scenario, so it is unclear what, if any, in situ reclamation would be required. For this reason, water requirements for reclamation are not included in Table 7-8.

The process units listed in the "Recycled" category use water as a heat transfer medium. Water flow rates for these units are determined from process flowsheet calculations in ProMax (bitumen recovery, hydrotreater and CO_2 compressor) or scaled from literature values (Maples [24] for the sulfur recovery unit and Fleshman [29] for the hydrogen plant). Water leaving these process units is sent to cooling towers before it is recycled. Water in the "Generated" category is produced during the condensation of oxy-fired flue gases. The volume of condensed water produced is calculated based on the mass flow rate of CO_2 and assumptions of complete combustion and recovery of all water in the flue gases (oxy-firing only).

Overall, the largest water use is for the drilling and completion of the 960 wells required for the base case (high initial permeability) scenario. Each well is assumed to require 3.6 million gallons of water for drilling and completion [41]. Because this water is trucked in as part of the drilling process, it is not included in the capacity of the reservoir or water pipeline; costs for this water are included in the costs of drilling and completion. Upgrading is a minor water consumer in this scenario. A small amount of water in the form of steam is consumed as a reactant in the hydrogen plant. In the upgrader, there are evaporative losses from the cooling towers, listed as "Cooling Tower Makeup" in Table 7-8, and steam recycle losses, which are estimated to be 3% by volume for steam generation in a closed cycle loop. As described in Section 6.2.4, other small water uses/losses are assumed to be negligible and are not included in the water accounting. Also, the volume of water required for the one-time filling of tanks for startup is not included in Table 7-8.

This estimate was obtained from Table B.6.1.1 in Connacher's SAGD report [42].

Given the proximity of the in situ oil shale scenario to the ex situ oil shale scenario, it shares the same potential sources of water, the Green River and its tributary, the White River. The White River is 1.6 miles (2.6 kilometers) from the scenario location. As discussed in Section 6.2.4, the average monthly flow rate of the White River is 692 CFS (19.6 CMS), which is orders of magnitude larger than the water used by this process at full production with water for drilling excluded (0.285 CFS or 0.0081 CMS).

The White River's highest recorded monthly flow rate is 4,363 CFS (123.5 CMS) and the lowest is 73.1 CFS (2.07 CMS).

The in situ production and upgrading processes require water on a daily basis plus a one-time filling of the reservoir for startup. For this scenario, water is purchased at a rate of $50 per acre-foot per year (see Table 5-7) from those with agricultural water rights [44]. As discussed in Section 6.2.4, assuming that water rights are available for purchase, the effect on profitability of owning water rights versus purchasing water rights is negligible.

The purchased water is diverted or pumped from the White River and transferred via a short water pipeline to the plant site to fill the water storage reservoir for daily use. The capital and operating costs for the water pipeline, assumed to run in a straight line between the site and the river, are included in this analysis.

The size of the reservoir is determined by the duration of a prolonged drought in the area (90 days; see Section 6.2.4) and the water utilization for air-fired and oxy-fired processes excluding drilling (see Table 7-8). The estimated reservoir sizes are 51.1 acre-feet (63,000 cubic meters) for the air-fired case and 54.7 acre-feet (67,400 cubic meters) for the oxy-fired case. Costs for the lined water reservoirs are computed using construction excavation costs that are applicable in the Uinta Basin [36]; they are estimated to be $0.921 million and $0.973 million for the air- and oxy-fired operations, respectively.

The reservoir is sized for water utilization at the maximum production capacity of 50,000 BPD.

7.3 Supply Cost Analysis of In Situ Oil Shale Production Scenario

All dollar values given in this section are reported as 2012 US$ unless otherwise noted. An inflation rate of 1.8% is used to adjust dollar values from other reports to 2012 US$, except for instances where more specific inflation indices are available.

The profitability analysis performed for this scenario is the same as that outlined in Section 6.3: an estimation of capital costs, a "base case" Supply Price Method profitability analysis as a function of hurdle rate, an NPV profitability analysis based on EIA oil price forecasts and defined hurdle rates, and a Supply Price Method sensitivity analysis. Raw shale oil production costs at the mine site (excluding upgrading and transportation costs) are also included for comparison. Both the Supply Price Method and the NPV Method consider all the costs associated with SCO production as described in Section 5.4. All costs and profitability measures are reported in terms of real dollars.

Table 7-9 lists the key assumptions for the base in situ oil shale cases using air-fired and oxy-fired combustion for plant heating. "Merchant upgrader" refers to how the upgrader (brought online at the beginning of year five) is utilized. For the base case, "No" means the upgrader is operated on an "as needed" basis with operation at full capacity (330 days of operation per year) not occurring until the last year of the project (2035). The impact on profitability of operating as a merchant upgrader is explored in Section 7.3.4. With both air-firing and oxy-firing, all of the process heat and the fuel required by the electric heaters is supplied by purchased natural gas supplemented by methane-rich streams produced from in situ heating.

For the merchant upgrader, raw shale oil is purchased to supplement the production volume such that the upgrader is operating at full capacity for the last 18 years of the project.

Table 7-9. In situ oil shale scenario base case assumptions.

Category	Input/assumption
Air- & oxy-fired	
Average oil shale grade	25 GPT
Reservoir Permeability	20 mD
Reservoir Thickness	100 feet (30.5 meters)
Oil recovery	In situ heating - < 34 wt% after 24 years Hydrotreater - 98.1 wt%
Hydrogen consumption	129 SCF/bbl
Merchant upgrader	No
Utility pricing	Fixed prices from Table 5-7
Hurdle Rate	0–6%
Taxes and Royalties	Federal: 35% of Taxable Income State: 5% of Taxable Income Property: 1% of Total Permanent Investment Severance[a]: 3–5% of Adjusted Wellhead Price Conservation Fee: 0.2% of Adjusted Wellhead Price Oil Royalty[a]: 5–12.5% of Oil Sales
Product	WTI-quality SCO
Air-fired	
CO_2 tax	None
Revenue	Oil, sulfur, and steam
Oxy-fired (upgrading only)	
CO_2 sales	$25/ton
Revenue	Oil, CO_2, sulfur, and steam

[a] *See Section 5.4.3 for scenario accounting details related to tax and royalty rates.*

As discussed in Section 5.2, the timeline for the in situ oil shale project differs significantly from other scenarios in this report because of how long in situ oil retorting takes to reach peak production (27 years for the first wells drilled versus six years in all other scenarios). Production gradually increases each year until full production is reached in 2035. All wells are drilled in four years starting in 2013 (year two of the project). The number of wells drilled is designed so that production will reach full processing capacity (90%) in 2035 to avoid producing more oil than can be upgraded during the project timeline. Oil produced prior to completion of upgrading and pipeline facilities is transported by truck and sold at a discount to refiners as discussed in Section 7.1.2. All other aspects of this scenario's project timeline are identical to the other scenarios in this report.

Table 7-10 lists the major outputs from and inputs to the in situ production of SCO from oil shale on a per barrel basis. The CO_2 emitted by the electrical generators is dilute and is emitted into the atmosphere. For the oxy-fired scenario, the CO_2 released by the upgrading process has been captured, is of pipeline-quality, and can be sold. On a per barrel basis, CO_2e emissions for in situ production are nearly double those of ex situ production with a Tosco II retort and approximately 20% greater than ex situ production with a Paraho retort. Relative to raw shale oil produced ex situ, the raw shale oil produced in situ has a much lower H_2 requirement during hydrotreating, which results in reduced CO_2e emissions for the upgrading step. However, this reduction is offset by the significant energy requirements of heating the resource underground and the long time delay from the initiation of heating to the start of significant production, resulting in the overall increases in CO_2e emissions noted.

To provide H_2 for hydrotreating raw shale oil produced ex situ (e.g. fast heating rates), 48,900,000 MMBtu per year of natural gas are required at full production (50,000 BPD) while for raw shale oil produced in situ (e.g. slow heating rates), the requirement is 3,100,000 MMBtu per year .

Table 7-10. Major process outputs and inputs on a per barrel basis.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	9.64	9.64	lb
	CO_2 [a]			
	Emitted to Atmosphere	998	955	lb
	Sold to Pipeline	-	59	lb
	Steam (600 psig, 700°F)	25	25	lb
	Sulfur	2.09	2.09	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	10.68	14.78	kWh
	Fuel [b]			
	Purchased	6.44	6.44	MMBtu
	Total	7.01	7.00	MMBtu
	Makeup Water [c]	0.74	0.74	bbl
	O_2	-	72	lb
	Refrigerant	2.72	2.72	MJ
	Steam			
	50 psig	266	266	lb
	450 psig	77	77	lb

[a] *The per barrel CO_2 output is CO_2e. These emissions do not include those associated with facilities construction, refrigeration, water treatment, or decomposition of carbonates in the oil shale; see Section 7.2.3.*
[b] *The fuel input refers to natural gas only. The difference between the total fuel used and that purchased is the fuel credit. It is the produced gas that is supplied as a by-product of in situ oil shale retorting.*
[c] *The makeup water includes the water required for drilling. If the water for drilling is excluded, makeup water is 0.09 bbl/bbl of oil.*

The increased electricity usage for the oxy-fired case is due to the power consumption of the CO_2 compression system. Also, O_2 is a required input for the oxy-fired system. Otherwise, the per barrel inputs are very similar between the air-fired and oxy-fired systems.

7.3.1 Capital Costs for In Situ Oil Shale Extraction

The total capital investment for the complete air-fired production facility is \$6.02 billion; that of the oxy-fired plant is \$6.08 billion. A breakdown of all capital costs is shown in Table 7-11; definitions for all cost categories can be found in Section 5.3.4. The largest capital costs for the air-fired heating system are the drilling (48%), the electrical generators for in situ retorting (11%), and the hydrotreater (8%). These percentages are only slightly changed for the oxy-fired case.

For this scenario, oxy-firing is only implemented in the upgrading sections of the process.

Table 7-11. Capital cost breakdown by unit for the base case in situ oil shale scenario in millions of 2012 US$.

Category	Item	Air-fired	Oxy-fired
Total Bare Module Investment - C_{TBM}	In-Situ Retort	$ 659.3	$ 659.3
	Fractionator	$ 44.0	$ 44.0
	Hydrotreater	$ 486.0	$ 494.0
	H_2 Plant	$ 17.1	$ 17.1
	Sour Water Stripper	$ 10.7	$ 10.7
	Amine Treatment Unit	$ 2.2	$ 2.2
	Sulfur Recovery Unit	$ 6.2	$ 6.2
	CO_2 Compressor	$ -	$ 16.0
	C_{TBM} Subtotal	**$ 1,225.6**	**$ 1,249.5**
Total Direct Permanent Investment - C_{DPI}	Site Preparation	$ 122.6	$ 125.0
	Service Facilities	$ 122.6	$ 125.0
	Oil Pipeline	$ 104.3	$ 104.3
	Water Pipeline	$ .4	$ .4
	Water Reservoir	$ .9	$ 1.0
	Allocated Costs for Utility Plants	$ 50.6	$ 55.0
	C_{DPI} Subtotal	**$ 1,626.9**	**$ 1,660.1**
Total Depreciable Capital - C_{TDC}	Contingency	$ 244.0	$ 249.0
	C_{TDC} Subtotal	**$ 1,870.9**	**$ 1,909.2**
Total Permanent Investment - C_{TPI}	Land	$ 37.4	$ 38.2
	Permitting	$ 12.7	$ 12.7
	Royalties for Intellectual Property	$ 37.4	$ 38.2
	Startup	$ 187.1	$ 190.9
	Investment Site Factor [a]	1.15	1.15
	Drilling	$ 2,923.5	$ 2,923.5
	Well Reclamation	$ 28.4	$ 28.4
	C_{TPI} Subtotal - US Midwest	**$ 5,419.3**	**$ 5,469.4**
Total Capital Investment - C_{TCI}	Working Capital	$ 596.5	$ 612.8
	Total ($)	**$ 6,015.7**	**$ 6,082.2**

[a] *The investment site factor is used to adjust C_{TDC} and the line items of C_{TPI} above it (Land, Permitting, Royalties for Intellectual Property, and Startup). However drilling and reclamation costs, which are already costed for the US Midwest Region, are not adjusted by the investment site factor.*

These capital costs are similar to those for ex situ oil shale production. While the upgrading requirements for shale oil produced in situ (C_{TBM} = $566.3 million) are not as extensive as those for shale oil from a surface retort (C_{TBM} = $1,052.4 million for Tosco II retort), the cost of drilling ($2,923.5 million) offsets the effect of the reduced upgrading costs.

Based on the "average" daily production for this project of 15,134 BPD (see Section 7.1.1.1), the CPFB is $397,499 for the air-fired case and $401,893 for the oxy-fired case; these values are three times greater than the CPFB for the ex situ oil shale scenario. With upgrading costs excluded, the CPFB is $318,308 for both the air- and oxy-fired cases. While there are no commercial in situ oil shale operations with which to compare, the CPFB for five commercial in situ oil sands operations (SAGD only; upgrading costs not included) ranges from \$22,981 (35,000 BPD operation) to \$32,969 (10,000 BPD operation) [45].

The CPFB values for the commercial oil sands operations have been adjusted to 2012 US\$ using the CEPCI inflation index and a C\$/US\$ exchange rate of 1:1.

For the accelerated-heating case, where the first seven years of heating are skipped over and production in year two begins at year 8 levels from Figure 7.7, the average production over the life of the project increases to 22,573 BPD and the CPFB is reduced to \$162,543 for the air-fired case and to \$163,267 for the oxy-fired case. The 59% drop in CPFB is greater than the 49% increase in average production because far fewer wells are required to meet the 50,000 BPD production rate by the end of the project.

Normal heating rates require 960 wells to be drilled versus 664 for the accelerated heating case.

While the 2008 RAND report on oil shale does not provide any estimates of capital costs for an in situ production process, the authors state that "the Shell approach is.... more akin to a conventional petroleum drilling process.... As such, it benefits from the technical advances and accompanying cost reductions achieved by the petroleum extraction industry over the past 25 years" [37]. The Shell approach as reported employs vertical well drilling technology with tightly spaced wells (35–42 feet or 10.7–12.8 meters apart) [25]. The implication is that drilling costs will be lower than capital costs for mining and surface retorting. However, the capital costs computed for this scenario, which are based on the reported costs of drilling wells in the Uinta Basin, the depth and thickness of the target oil shale zone, and the simulated production curves, show a cost penalty, not benefit, associated with drilling due to the total number of wells that must be drilled to meet 50,000 BPD production numbers by the end of the project lifetime.

7.3.2 Supply Price Evaluation of In Situ Oil Sands Base Case

The supply price at a specified hurdle rate is computed by finding the real fixed price that results in NPV = 0 with the discount factor computed from the hurdle rate; see Section 5.2.2 for additional details.

7.3.2.1 Base Case Supply Prices

The base case supply price as a function of hurdle rates up to 6% is given in Table 7-12 for air-fired combustion and in Table 7-13 for oxy-fired combustion. All supply costs listed in Tables 7-12 and 7-13 are positive contributors to the supply price while all non-oil revenue streams are negative contributors. The supply costs from Table 7-12 for air-fired combustion are plotted in Figure 7.13 while the supply costs from Table 7-13 for oxy-fired combustion are plotted in Figure 7.14.

See Section 5.2.2 for details on how supply price is determined.

Oxy-firing is considered only for the unit operations associated with upgrading, not for generation of electricity for the downhole heaters; see Section 7.1.1.4.

Table 7-12. Supply price for air-fired in situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%
Drilling	$ 23.00	$ 23.00	$ 23.00	$ 23.00
In Situ Retort [a]	$ 44.13	$ 44.13	$ 44.13	$ 44.13
Upgrading [b]	$ 12.42	$ 12.42	$ 12.42	$ 12.42
Taxes	$ 47.66	$ 61.05	$ 78.63	$ 101.92
Oil Royalties	$ 22.05	$ 27.03	$ 33.42	$ 41.66
Net Earnings	$ -	$ 22.73	$ 51.47	$ 87.93
Maintenance	$ 14.72	$ 14.72	$ 14.72	$ 14.72
Other [c]	$ 19.41	$ 19.68	$ 20.04	$ 20.50
Supply Cost	**$ 183.39**	**$ 224.76**	**$ 277.82**	**$ 346.27**
Other Revenue	$ 0.18	$ 0.18	$ 0.18	$ 0.18
Oil Supply Price	**$ 183.21**	**$ 224.58**	**$ 277.64**	**$ 346.08**

[a] *"In Situ Retort" includes all costs associated with the natural-gas fired generators and the electrical heaters.*
[b] *"Upgrading" includes all costs associated with the fractionator, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.*
[c] *"Other" includes all costs associated with the oil pipeline, water pipeline, allocated costs for utility plants, water reservoir, site preparation, service facilities, contingency, permitting, research, administration, incentive compensation, insurance, intellectual property royalties, overhead, land, startup, and CO_2 compressor (oxy-firing only).*

Table 7-13. Supply price for oxy-fired in situ oil shale production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%
Drilling	$ 23.00	$ 23.00	$ 23.00	$ 23.00
In Situ Retort	$ 44.13	$ 44.13	$ 44.13	$ 44.13
Upgrading	$ 15.04	$ 15.04	$ 15.04	$ 15.04
Taxes	$ 48.18	$ 61.71	$ 79.48	$ 102.99
Oil Royalties	$ 22.58	$ 27.61	$ 34.06	$ 42.39
Net Earnings	$ -	$ 22.98	$ 52.03	$ 88.88
Maintenance	$ 15.02	$ 15.02	$ 15.02	$ 15.02
Other	$ 20.54	$ 20.81	$ 21.17	$ 21.64
Supply Cost	**$ 188.48**	**$ 230.29**	**$ 283.93**	**$ 353.08**
Other Revenue	$ 0.92	$ 0.92	$ 0.92	$ 0.92
Oil Supply Price	**$ 187.56**	**$ 229.37**	**$ 283.01**	**$ 352.16**

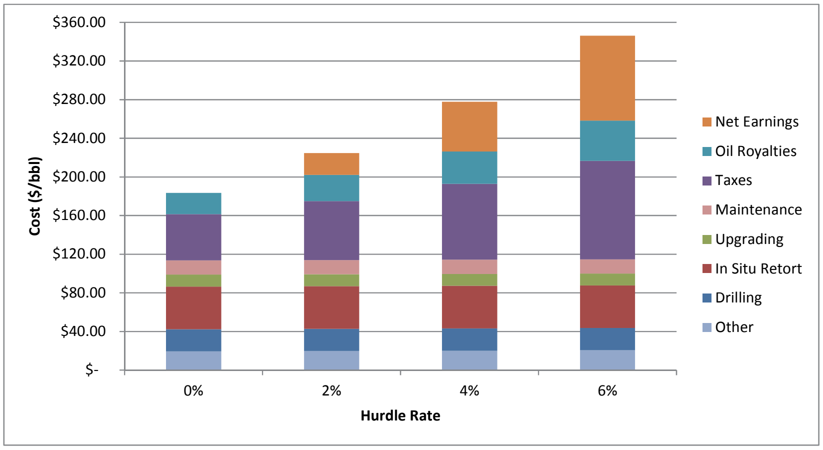


Figure 7.13: Supply cost for air-fired in situ oil shale production scenario as a function of hurdle rate.

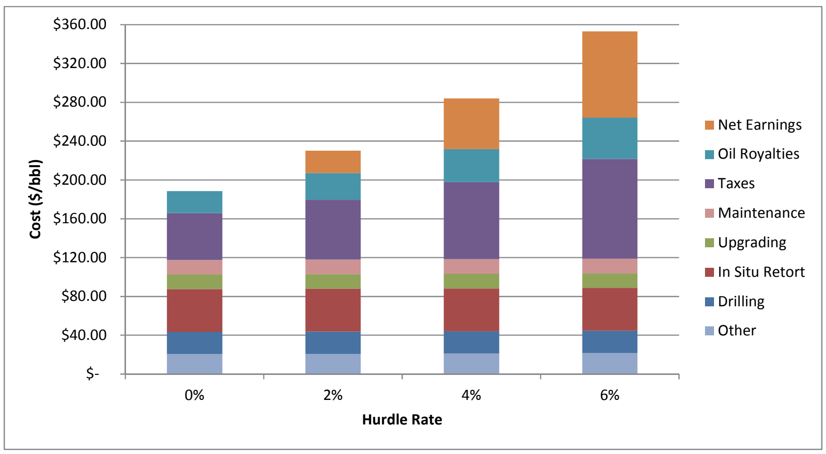


Figure 7.14: Supply cost for oxy-fired in situ oil shale production scenario as a function of hurdle rate.

The supply price to produce refinery-ready SCO for hurdle rates ranging from 0–6% is $183.21–$346.08/bbl for the air-fired case and $187.56–$352.16/bbl for the oxy-fired case. These supply prices include all costs (capital and operating expenses, taxes, royalties, net earnings computed from the hurdle rate) and all non-oil revenue streams. The supply cost at a hurdle rate of 0% is the cost of the project without any investor profit. Due to the high supply prices associated with this scenario, additional hurdle rates were not investigated.

The high supply prices are driven by three factors. First, drilling costs are high compared with the costs of construction for a mine and they are incurred in years two through five of the project when there is essentially no cash flow. Second, in situ retorting is five times the cost of surface retorting, mostly due to the cost of natural gas to supply the electrical generators; see Section 7.3.2.3. Third, there is a long lag period between the initiation of heating and the start of significant production levels (e.g. cash flow) due to the poor conductive heat transfer properties of oil shale. For example, it takes 13 years from project initiation to reach a 10,000 BPD production level. Due to these cash flow issues, the supply price of oil must be very high, which drives up the supply cost of cost components that are dependent on oil price such as taxes, royalties, incentive pay, and net earnings.

For the air-fired case at a 0% hurdle rate, the highest costs are for taxes ($47.66), in situ retorting ($44.13/bbl), drilling ($23.00/bbl), and royalties ($22.05/bbl). At a 6% hurdle rate, the highest cost categories are taxes ($101.92/bbl), net earnings ($87.93/bbl), in situ retorting ($44.13/bbl), and royalties ($41.66/bbl). Taxes are tied to net earnings, which rise with increasing hurdle rate; see Figure 7.15 in Section 7.3.2.2. The highest cost categories remain the same for the oxy-fired system as oxy-firing only impacts the upgrading process, which is not a significant cost component for this in situ scenario.

The capture of CO_2 increases costs by $5.27–$7.00/bbl depending on the hurdle rate while the sale of CO_2 nets only $0.74/bbl. Taxing CO_2 at the rate of $25 per ton increases the base case supply price for air-firing by $6.04 to $189.25/bbl (0% hurdle rate), which is similar to the extra cost of oxy-firing ($5.27/bbl at a 0% hurdle rate). Because CO_2 is a product that is sold in the oxy-firing case, the supply price of oxy-firing ($187.56, 0% hurdle rate) is lower than the supply price of air-firing with the CO_2 tax ($189.25, 0 % hurdle rate).

CO_2 capture costs from the electrical generators for downhole heating are not included in this analysis.

7.3.2.2 Supply Costs that Vary with Hurdle Rate

The effect of cost components that are functions of oil price is shown in Figure 7.15. State and federal corporate income taxes and incentive compensation are zero until the oil price reaches about $38/bbl, at which price cash flow during production years becomes positive; above this point, federal taxes increase rapidly with oil price. The net earnings remain negative until oil sells for at least $183/bbl for the air-fired base case and $189/bbl for the oxy-fired base case, at which point the supply cost of net earnings rises faster than federal taxes.

Net earnings are not positive until NPV = 0.

See "Net Earnings" column in Tables 7-12 and 7-13.

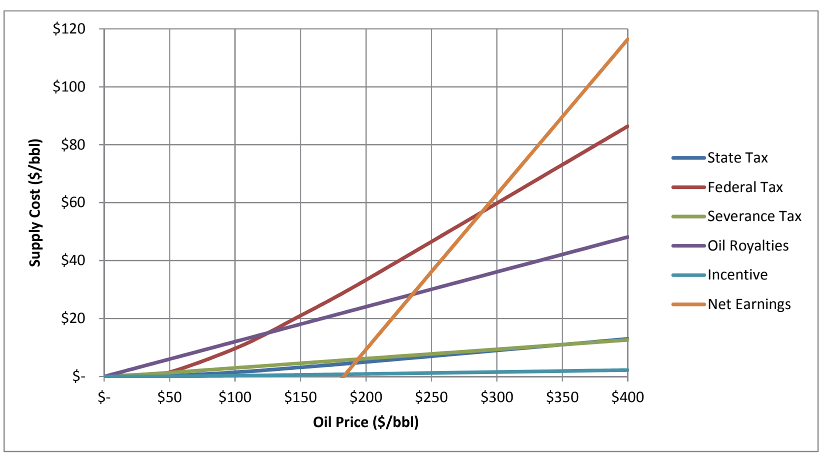


Figure 7.15: Supply cost ($/bbl) of cost components that are dependent on oil price.

"Incentive" refers to incentive compensation.

7.3.2.3 Detailed Supply Price Breakdowns

Detailed supply price breakdowns for both air- and oxy-firing at a 0% hurdle rate are given in Tables 7-14 and 7-15. Note that water costs do not include the water required for drilling. Due to rounding error, the "Total" column may differ from the sum across any given row by $0.01. With the exception of the supply costs tied to the price of oil that are shown in Figure 7.15, all costs listed in Tables 7-14 and 7-15 are fixed with respect to hurdle rate. Also, fuel cost in these tables refers only to natural gas and does not include diesel or other types of fuels that might be necessary to operate equipment, vehicles, etc.

Table 7-14. Detailed supply price breakdown for air-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Drilling	$ 23.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.00
	In-Situ Retort	$ 5.96	$ 0.25	$ -	$ 37.92	$ -	$ -	$ -	$ -	$ 44.13
Upgrading	Hydrotreater	$ 4.40	$ 1.10	$ 0.46	$ 1.75	$ 0.00	$ -	$ -	$ 0.08	$ 7.79
	H_2 Plant	$ 0.15	$ 0.37	$ 0.00	$ 1.11	$ 0.00	$ -	$ -	$ -	$ 1.64
	Fractionator	$ 0.40	$ 0.12	$ 0.03	$ 0.60	$ 0.00	$ 0.07	$ -	$ -	$ 1.22
	Sour Water Stripper	$ 0.10	$ 0.25	$ 0.01	$ -	$ 0.00	$ 0.04	$ -	$ -	$ 0.39
	Amine Treatment Unit	$ 0.02	$ 0.25	$ 0.00	$ -	$ 0.00	$ 0.69	$ -	$ -	$ 0.95
	Sulfur Recovery Unit	$ 0.06	$ 0.37	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.43
Delivery	Oil Pipeline	$ 0.94	$ -	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ 1.07
Other	Water Pipeline	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 0.00
	CO_2 Compressor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 0.46
		R-134a	Water Reservoir	$ 0.01
			Site Preparation	$ 1.11
	** Taxes includes:	State Tax	Service Facilities	$ 1.11
		Federal Tax	Contigency	$ 2.21
		Severance Tax	Permitting	$ 0.12
		Property Tax	Maintenance	$ 14.72
			Overhead	$ 2.39
			Research	$ 0.74
			Administration	$ 0.35
			Incentive Compensation	$ 0.77
			Insurance	$ 3.41
			Crude Price Differential and Transport	$ 0.03
			Taxes**	$ 47.66
			Royalties - Oil	$ 22.05
			Royalties - IP	$ 3.39
			Working Capital	$ -
			Well Reclamation	$ 0.22
			Land	$ 0.34
			Startup	$ 1.69
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 183.39**
			CO_2	$ -
			Export Steam	$ 0.09
			Sulfur	$ 0.09
		Non-Oil Revenue Subtotal		**$ 0.18**
Oil Supply Price				**$ 183.21**

Table 7-15. Detailed supply price breakdown for oxy-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Drilling	$ 23.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.00
	In-Situ Retort	$ 5.96	$ 0.24	$ -	$ 37.92	$ -	$ -	$ -	$ -	$ 44.13
Upgrading	Hydrotreater	$ 4.47	$ 1.10	$ 0.53	$ 1.72	$ 0.00	$ -	$ 1.50	$ 0.08	$ 9.41
	H_2 Plant	$ 0.15	$ 0.37	$ 0.00	$ 1.09	$ 0.00	$ -	$ 0.44	$ -	$ 2.06
	Fractionator	$ 0.40	$ 0.12	$ 0.03	$ 0.60	$ -	$ 0.07	$ 0.58	$ -	$ 1.80
	Sour Water Stripper	$ 0.10	$ 0.24	$ 0.01	$ -	$ 0.00	$ 0.04	$ -	$ -	$ 0.39
	Amine Treatment Unit	$ 0.02	$ 0.24	$ 0.00	$ -	$ 0.00	$ 0.69	$ -	$ -	$ 0.95
	Sulfur Recovery Unit	$ 0.06	$ 0.37	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.43
Delivery	Oil Pipeline	$ 0.94	$ -	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ 1.07
Other	Water Pipeline	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 0.00
	CO_2 Compressor	$ 0.15	$ 0.24	$ 0.17	$ -	$ 0.02	$ -	$ -	$ 0.08	$ 0.66

Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 0.50
		R-134a	Water Reservoir	$ 0.01
			Site Preparation	$ 1.13
	** Taxes includes:	State Tax	Service Facilities	$ 1.13
		Federal Tax	Contigency	$ 2.25
		Severance Tax	Permitting	$ 0.12
		Property Tax	Maintenance	$ 15.02
			Overhead	$ 2.48
			Research	$ 0.74
			Administration	$ 0.38
			Incentive Compensation	$ 0.78
			Insurance	$ 3.44
			Crude Price Differential and Transport	$ 0.03
			Taxes**	$ 48.18
			Royalties - Oil	$ 22.58
			Royalties - IP	$ 3.53
			Working Capital	$ -
			Well Reclamation	$ 0.22
			Land	$ 0.35
			Startup	$ 1.73
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 188.48**
			CO_2	$ 0.74
			Export Steam	$ 0.09
			Sulfur	$ 0.09
		Non-Oil Revenue Subtotal		**$ 0.92**
Oil Supply Price				**$ 187.56**

It is clear from this breakdown that the cost of in situ retorting is driven by the cost of fuel to fire the electrical generators, not by the cost of drilling (capital cost). The total fuel cost for the air-fired scenario is $41.38 with $37.92 of that total allocated to in situ heating. For the ex situ oil shale scenario, the total fuel costs are $7.65 (Tosco II, air-fired) and $12.39 (Paraho Direct, air-fired). Increasing the fuel efficiency of the heating process is a primary economic concern.

Although water acquisition and management are also significant concerns with respect to oil shale development, the costs of purchasing, delivering, and treating water are minimal ($0.03/bbl for both air- and oxy-firing). The cost of the water pipeline and the water for the various processes in Tables 7-14 and 7-15 is so small that it rounds down to $0. These negligible costs for water are driven by three factors: (1) the total does not include the cost of the water required for drilling, which is included in the capital cost of drilling/completion, (2) the per barrel water consumption for other unit operations is greatly reduced compared with the ex situ oil shale scenario, and (3) the water requirements associated with handling of mined material are eliminated.

Total water costs can be determined by adding up the "Water" column entries, the "Water Pipeline" row entries, and the "Water Reservoir" entry.

The increased cost for oxy-firing is mostly due to the cost of O_2 ($2.52/bbl) with small increases also noted for the electricity and labor needed for the CO_2 compression system. However, because the electrical generators for in situ heating are excluded from the oxy-firing system (see Section 7.1.1.4), it is not possible to analyze the full impact of switching to oxy-firing for all heating systems.

7.3.3 Supply Price Evaluation for Production of Raw Shale Oil

The supply prices given in the previous section are for producing SCO delivered to refining markets in Salt Lake City. In this section, supply prices for producing raw shale oil at the plant gate are determined by zeroing out the costs associated with upgrading and delivery in the Supply Price Method as described in Section 6.3.3. The supply costs by category are listed in Table 7-16 as a function of hurdle rate. The supply price is the same as the supply cost as there are no non-oil revenue streams.

Excluded costs are those for the hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, sulfur recovery unit, CO_2 compressor (if applicable), and oil pipeline. Included costs are those for drilling, electrical heating, water pipeline, reservoir, and all cost categories that are functions of other costs (service facilities, site preparation, land purchase, utility plants, etc.).

Plant gate supply costs do not include the cost of treatment of waste streams.

Table 7-16. Plant gate raw shale oil supply cost/price as a function of hurdle rate for ex situ oil sands production.

Hurdle Rate	0%	2%	4%	6%
Drilling	$ 23.00	$ 23.00	$ 23.00	$ 23.00
In Situ Retort	$ 44.13	$ 44.13	$ 44.13	$ 44.13
Upgrading	$ -	$ -	$ -	$ -
Taxes	$ 37.59	$ 48.15	$ 62.11	$ 80.49
Oil Royalties	$ 16.89	$ 20.79	$ 25.81	$ 32.26
Net Earnings	$ -	$ 17.74	$ 40.16	$ 68.58
Maintenance	$ 7.27	$ 7.27	$ 7.27	$ 7.27
Other	$ 11.19	$ 11.40	$ 11.67	$ 12.03
Supply Cost	**$ 140.06**	**$ 172.47**	**$ 214.15**	**$ 267.76**
Other Revenue	$ -	$ -	$ -	$ -
Oil Supply Price	**$ 140.06**	**$ 172.47**	**$ 214.15**	**$ 267.76**

While the "plant gate" costs for raw shale oil produced in situ are significantly lower than for upgraded SCO delivered to market (see Table 7-12), the supply price is still higher than the EIA high forecast for WTI oil prices by $75.31 at the relatively low hurdle rate of 6%.

Despite being of a higher quality than raw shale oil produced ex situ, raw shale oil produced in situ would most likely be sold at a discount to WTI because of high sulfur and nitrogen content.

7.3.4 Net Present Value for Various Price Forecasts

The profitability of the air-fired base case is measured using the NPV Method with three EIA energy price forecasts: low, reference, and high [47]. The NPV is computed using the hurdle rate to discount the cash flows. For the air-fired base case, Table 7-17 lists the NPV computed using the three EIA price forecasts for hurdle rates ranging from 0–6%.

See Section 5.2.3 for details about the NPV Method.

Table 7-17. NPV of air-fired base case scenario (in billions of 2012 US$).

Hurdle Rate	EIA Price Forecast		
	Low	Reference	High
0.0%	$ (9.02)	$ (2.94)	$ 1.45
1.1%	$ (8.66)	$ (3.63)	$ -
2.0%	$ (8.36)	$ (4.07)	$ (.97)
4.0%	$ (7.77)	$ (4.70)	$ (2.47)
6.0%	$ (7.24)	$ (5.02)	$ (3.40)

For the in situ oil shale base case scenario, the operation is not profitable for either the low or reference EIA price forecasts. Assuming the EIA high price forecast, the IRR is 1.1%, which by definition is the hurdle rate for which NPV = 0. Investors in the project will not receive a reasonable return on their investment unless the price of WTI-quality oil rises much higher than the EIA high price forecast.

Any combination of price forecast/hurdle rate that has a negative NPV is not profitable as profits will be less than the specified hurdle rate.

If the accelerated production schedule discussed in Section 7.3.1 could be achieved, the profitability of the operation would improve significantly. Table 7-18 lists the NPV computed for the air-fired case assuming the accelerated production schedule. Results for the three EIA prices forecasts with hurdle rates ranging from 0–6% are shown.

With the accelerated production schedule, the production rate in year two is that obtained from the simulation after seven years of heating.

Table 7-18. NPV of air-fired scenario with accelerated production (in billions of 2012 US$).

Hurdle Rate	EIA Price Forecast		
	Low	Reference	High
0.0%	$ (3.21)	$ 5.14	$ 11.42
2.0%	$ (3.60)	$ 2.47	$ 7.04
4.0%	$ (3.79)	$ .69	$ 4.09
5.1%	$ (3.84)	$ -	$ 2.91
6.0%	$ (3.86)	$ (.48)	$ 2.08
8.0%	$ (3.85)	$ (1.27)	$ .70
9.4%	$ (3.81)	$ (1.65)	$ -

Even with the accelerated production schedule, this scenario is not profitable (negative NPV) under the low energy price forecast. However, the IRR for the EIA reference forecast is 5.1% and for the high forecast is 9.4%, meaning the operation is profitable for hurdle rates less than the corresponding IRR. However, these values of IRR are low compared to the risks.

7.3.5 Supply Price Sensitivity

Using the Supply Price Method, the sensitivity of the supply price of oil to the following parameters is investigated: reservoir permeability, drilling and completion costs, production schedule, maintenance costs, fuel expenses (e.g. natural gas), and tax and royalty rates applied to the operation. For drilling and completion costs, maintenance costs, and fuel expenses, high and low values relative to the base case are assumed (see Table 7-19) and the resulting supply price is computed. Only low values relative to the base case are assumed for the reservoir permeability, federal corporate income tax, and state corporate income tax parameters. For the production schedule, only an accelerated schedule relative to the base case is considered. Table 7-19 lists the supply price as a function of hurdle rate for the range of parameters tested.

The first seven years of the production curve shown in Figure 7.7 are skipped in the accelerated production schedule.

Table 7-19. Sensitivity of supply price for in situ oil shale scenario to various parameters.

In Situ Oil Shale (Air-Fired)		Supply Price of Oil ($/bbl)			
		Hurdle Rate			
Variable	Range	0%	2%	4%	6%
Base Case	---	**$ 183.32**	**$ 224.69**	**$ 277.75**	**$ 346.19**
Reservoir Permeability	**20 mD**				
Low	1 mD	$ 252.47	$ 314.38	$ 395.94	$ 503.46
Drilling & Completion Costs	**$3.0 M**				
Low	$1.5 M	$ 158.46	$ 191.66	$ 234.00	$ 288.13
High	$4.5M	$ 208.32	$ 257.90	$ 322.04	$ 404.91
Production Schedule	**---**				
Accelerated	7 years	$ 91.52	$ 107.74	$ 127.56	$ 151.51
Maintenance (% of C_{TDC})	**5%**				
Low	2%	$ 169.21	$ 209.03	$ 260.52	$ 327.05
High	8%	$ 197.44	$ 240.35	$ 295.17	$ 365.40
Fuel Costs	**100%**				
Low	50%	$ 153.65	$ 191.30	$ 240.17	$ 303.47
High	150%	$ 213.05	$ 258.18	$ 315.67	$ 389.15
Royalties (% of Sales) [a]	**5.0%-12.5%**				
Federal Land - standard fixed rate [b]	12.5%	$ 184.76	$ 226.81	$ 280.85	$ 350.47
SITLA [c]	8.0%-12.5%	$ 182.87	$ 224.17	$ 277.19	$ 345.54
Low [d]	5.0%	$ 170.38	$ 208.83	$ 258.10	$ 321.33
Federal Taxes (% of Taxable Income) [e]	**35%**				
Low [f]	15%	$ 159.73	$ 193.25	$ 235.85	$ 289.78
State Taxes (% of Taxable Income) [g]	**5%**				
SB65 Tax Credit [h]	< 2%	$ 180.33	$ 220.68	$ 272.38	$ 338.82
Combined	---				
All Unfavorable [i]	---	$ 352.34	$ 436.39	$ 546.66	$ 691.54
All Favorable [j]	---	$ 48.44	$ 57.30	$ 68.15	$ 81.25
Merchant Upgrader	---				
Small price differential	87%	$ 323.60	$ 444.53	$ 649.18	$ 1,058.88
Large price differential	50%	$ 126.49	$ 148.95	$ 176.16	$ 208.74

[a] *Royalty rate for oil shale/oil sands leases on state (SITLA) lands; see Section 3.4.1.1*
[b] *Standard fixed rate for conventional oil lease*
[c] *Royalty rate given in 2008 royalty rules; see Section 3.4.1.1*
[d] *Lowest royalty rate proposed on either federal or state lands*
[e] *Federal corporate income tax rate based on taxable income*
[f] *Lowest federal corporate income tax rate*
[g] *Standard state corporate income tax*
[h] *State corporate income tax rate after state tax credit is applied; see Section 3.4.4*
[i] *All unfavorable = Low reservoir permeability, high drilling and completion costs, base case production schedule, high maintenance costs, high fuel costs,12.5% royalty rate, federal income tax of 35%, state tax credit does not apply*
[j] *All favorable = High reservoir permeability, low drilling and completion costs, accelerated production schedule, low maintenance costs, low fuel costs, 5% royalty rate, federal income tax of 15%, state tax credit applies*

Over the ranges of parameters tested, the production schedule and the reservoir permeability have the largest impact on the supply price. Both of these parameters affect the raw shale oil production rate. Accelerating the production schedule by seven years results in an increase in oil production over the lifetime of the project of 62 million barrels, giving more cash flow in the early years of the project. It also reduces the cost of drilling and in situ retorting by 31%, equivalent to capital cost savings of $901 million for drilling and $203 million for in situ retorting, because of the reduction in the number of wells required to reach production levels of 50,000 BPD by 2035. Reducing the reservoir permeability to a value more typical of unfractured oil shale pushes out the production curve by approximately six years from the high initial permeability base case. Additionally, 1,408 wells are required to meet the same 50,000 BPD target in 2035, driving up drilling and retorting capital costs by 53%.

The accelerated production schedule illustrates the impacts of using a technology that reduces the lag time between the commencement of heating and the beginning of significant production.

For the base case, high initial permeability (20 mD) is assumed. Unfractured oil shales have low permeability, so 1 mD is considered to be a more realistic value.

Drilling and completion costs were selected for the sensitivity analysis to cover the uncertainty associated with the assumed costs for this scenario. Varying drilling costs by ± 50% changes the supply price of oil by ± $58/bbl at a 6% hurdle rate. However, because the base case supply price is so high, even a $58/bbl reduction is not enough to make the operation profitable under any of the EIA oil price forecasts. Hence, from an economic viewpoint, the key to success of in situ retorting is not improved drilling techniques but rather improved thermal treatment techniques that shorten the time required to produce oil (and perhaps the number of wells drilled) without sacrificing product quality.

Reducing the per well cost and/or drilling fewer wells would result in reduced drilling costs.

See Table 5-3 for a list a of average oil prices for the EIA low, reference, and high forecasts.

Fuel (e.g. natural gas) costs also have a significant impact on supply price. Altering the fuel costs ± 50% from the base case moves the supply price up or down by $30–$43/bbl depending on the hurdle rate, reflecting the large fuel consumption of the electrical generators. It should be noted that the base case natural gas consumption is a net value; it has been reduced by accounting for the heating value of the produced gas from the in situ retort, which supplies an average of 8% of the total fuel requirement. Lower fuel consumption might be achieved through alternate heating methods that reduce the overall heating time (e.g. through the introduction of fractures) or that more efficiently convert chemical energy from the fuel into downhole thermal energy (e.g. downhole natural gas burners).

The actual amount of produced gas available is computed on a monthly basis from the gas production curve shown in Figure 7.8.

Maintenance costs are estimated as a percentage of C_{TDC}, with recommended values ranging from 2% [31] to 11.5% [34] for various industrial processes. Since C_{TDC} is almost $1.9 billion, annual maintenance costs are in the hundreds of millions of dollars. Increasing or decreasing the base case value of 5% by three percentage points results in a $14–$19/bbl change in the supply price of oil depending on the hurdle rate.

A value specific to oil well maintenance was not found.

Table 7-19 shows the supply price for oil assuming a range of royalty and tax rates/credits that federal and state governments have suggested for oil sands and/or conventional oil development. The impact of tax and royalty policies increases with hurdle rate. Due to the high federal corporate income tax rate, changes to federal tax policy have a much larger impact on supply price than the recent Utah state tax credit for alternative energy development. At a hurdle rate of 6%, reducing the federal corporate income tax rate from 35% to 15% decreases the supply price of oil by $56.41 while applying the state tax credit results in a $7.37/bbl decrease in supply price. Considering royalty rates (6% hurdle rate), a fixed royalty rate of 5% reduces the supply price of oil by $24.86 over the base case while a fixed royalty rate of 12.5% raises the supply price of oil by $4.28.

Also evaluated in Table 7-19 is the impact on supply price of operating the upgrader at full capacity for 18 years by supplementing the produced shale oil with raw shale oil purchased from a local supplier. In the first years of production, purchases would be nearly 50,000 BPD; near the end of the project, very little shale oil would be purchased. To compute the price for purchased raw shale oil, a constant price differential between WTI-equivalent crude and raw shale oil is assumed. This price differential is represented as a percentage of WTI price in the Table 7-19. The small price differential (87% of WTI) represents the current price differential between WTI and Uinta Basin black wax crude [48]. The large price differential (50% of WTI) is lower than reported price differential for Western Canada Select, a blend of oil sands bitumen and conventional oil, and represents a likely upper bound on a price differential for purchased raw shale oil. With a small price differential, the economics implode. A large price differential for purchased raw shale oil results in supply prices that are reduced by 30–40% from the base case over the range of hurdle rates analyzed. These type of results are expected when a cost (e.g. raw shale oil purchase) is tied to the sale price of the product.

An API price discount of $0.75 is also applied to reflect the lower API of shale oil.

Western Canada Select was recently reported as trading at 57% of Brent crude, another reference fuel [49].

With the exception of the merchant upgrader, the combined effect on the supply price of applying all the favorable and unfavorable parameters in Table 7-19 is given as a function of hurdle rate. These "All Favorable" and "All Unfavorable" prices provide outer bounds on the supply price range. While the "All Favorable" option brings the supply price in the same range seen for the ex situ oil shale sensitivity analysis at similar hurdle rates, the "All Unfavorable" option yields a supply price that exceeds the upper range of of the ex situ analysis by a factor of more than two.

7.3.6 Analysis and Summary

While in situ oil shale extraction is attractive due to its reduced environmental footprint in terms of water demand and land disturbance, the costs of drilling a large number of horizontal wells and of heating a large underground volume of oil shale with low permeability and poor heat transfer properties are prohibitive in the current analysis. These results indicate the importance

This conclusion is based on the underlying assumption of oil and gas production rates obtained from the reservoir simulator.

of knowing the achievable production rate to a high degree of accuracy given the properties of the target formation and the heating technology. This level of predictivity will most likely be achieved through a combination of (1) pilot scale testing and (2) development of simulation tools that can accurately capture the effects of fracturing and/or rubblization on both heat transfer and fluid flow in the formation. Also, heating the deposit by other methods, e.g. radio frequency or microwave heating, may reduce supply costs if they allow the raw shale oil to be extracted from the deposit in less time and with fewer wells.

Detailed supply cost estimates for in situ oil shale production processes are not available in the open literature. As reported by Bartis et al. in the 2008 RAND report [37], "Shell anticipates that the petroleum products produced by its in-situ method are competitive, given crude oil prices in the mid-$20s per barrel. The company is still developing the process, however, and cost estimates are likely to increase as more information is obtained and more detailed designs become available. No independent cost estimates are available." The reference for this information is a short article by Sam Fletcher in the April 25, 2005 edition of the Oil & Gas Journal [46]. According to the article, Shell representative Jill Davis stated that, "The field research has shown that ICP produces high quality transportation fuels that are estimated to be economical at oil prices in the mid-$20s/bbl." However, no additional information is given about what costs/assumptions are included in this estimate.

As justification for such a low supply price compared to ex situ oil shale production, the RAND report lists comparative benefits: technical advances in drilling, lower up-front costs as capital expenditures could be made "incrementally as the areal extent of drilling increases," a reduced need for product upgrading, and lower reclamation costs. All of these issues are addressed in the present analysis. First, this report assumes that all drilling occurs during a four-year window in order to have sufficient heating time to meet required production levels (50,000 BPD) by the end of the project timeline (24 years). If heating could be accelerated, drilling could occur incrementally and still meet production goals. The sensitivity analysis in Section 7.3.4 considers the effect of accelerated heating on the supply price of SCO from in situ shale oil. With accelerated production at a low 6% hurdle rate, the supply price of $151.51 is between the average oil price of the EIA reference ($131.85) and high ($192.45) forecasts. Second, the reduced need for product upgrading was acknowledged in Section 7.1.5, but the cost benefit was not realized in this analysis because of the negative impact on cash flows from building the upgrader in the first four years of the project when it is not running at full capacity until year 24. This impact is seen by comparing the per barrel cost of upgrading for the in situ air-fired case ($12.42/bbl) to that for the ex situ air-fired case ($13.14/bbl for Tosco II). Third, reclamation costs are lower for the in situ scenario than the ex situ scenario ($0.22/bbl compared to $1.00/bbl in operating expenses plus capital costs for ex situ oil shale), but reclamation is such a small cost component that it has a negligible effect on the supply cost of either scenario.

Not discussed in the RAND report is the comparative disadvantage of trying to heat in situ large volumes of a material with low thermal conductivity. It is because of this poor heat transfer from the heat source to the formation that costs for this scenario are so high.

EROI values for the base and accelerated in situ oil shale production scenarios have been estimated by dividing the energy outputs (SCO) by the energy inputs. The inputs include the electricity and natural gas use for each of the processes described in this section, and the energy required for drilling, steam generation, water delivery, and O_2 production for the air separation unit. They do not include the energy required for facilities construction, water treatment or refrigeration. The EROI is 1.19 for the accelerated air-fired case, 0.72 for the air-fired base case, and 0.71 for the oxy-fired base case.

The fuel higher heating value is used as the basis for all energy inputs and outputs.

As with the ex situ oil shale scenario, the purpose of this analysis is to provide a transparent overview of the factors that impact profitability. Uncertainty is extremely high because of the lack of pilot-scale testing data and of adequate simulation tools. This analysis represents the first detailed supply cost information for shale oil production using in situ heating technology available in the open literature.

7.4 References

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8 Ex Situ Oil Sands Production Scenario

8 Ex Situ Oil Sands Production Scenario

This section provides a profitability analysis for producing SCO from Utah oil sands using an ex situ extraction process at a production capacity of 10,000 BPD. This ex situ production scenario includes surface mining with grinding, sand/oil separation in hydrocyclones using a hot water/solvent extraction process, primary and secondary upgrading, and pipelining of SCO to North Salt Lake City, Utah for refining. The scenario is located in the Asphalt Ridge-Whiterocks STSA southwest of Vernal, Utah, hereafter known as Asphalt Ridge. Figure 8.1 shows the scenario location within the Asphalt Ridge STSA. Asphalt Ridge rises from 500 to 1,000 feet (152 to 305 meters) above the Ashley Valley where it forms an escarpment on the northern edge of the Uinta Basin [1]. Bitumen-bearing rock outcrops on the face of this ridge. The deposit, following the Uinta, Duchesne River, and Green River formations, down dips to the southwest at 8 to 30 degrees, moving into the ridge as illustrated in Figure 8.2. The size of the Asphalt Ridge oil sands resource is estimated to be 1.05 billion barrels [2]. Asphalt Ridge is on federal (BLM) and state (SITLA) land as shown in Figure 8.3. The oil sand outcrop lies predominantly on BLM land while lands making up the down-dip of the deposit are primarily on state lands managed by SITLA. Land ownership within the Asphalt Ridge-Whiterocks STSA is as follows: BLM, 5,120 acres; National Forest, 1,920 acres; SITLA, 17,976 acres; private, 1,600 acres; Indian, 9,920 acres [1]. The Uintah and Ouray Indian Reservation boundary lies about 8 miles (15 kilometers) west of the Asphalt Ridge deposit. For the purposes of determining tax and royalty payments (see Section 3.4), the predominant landowner is assumed to be SITLA.

Ashley Valley is situated between 5,200–5,500 feet (1585–1676 meters) in elevation.

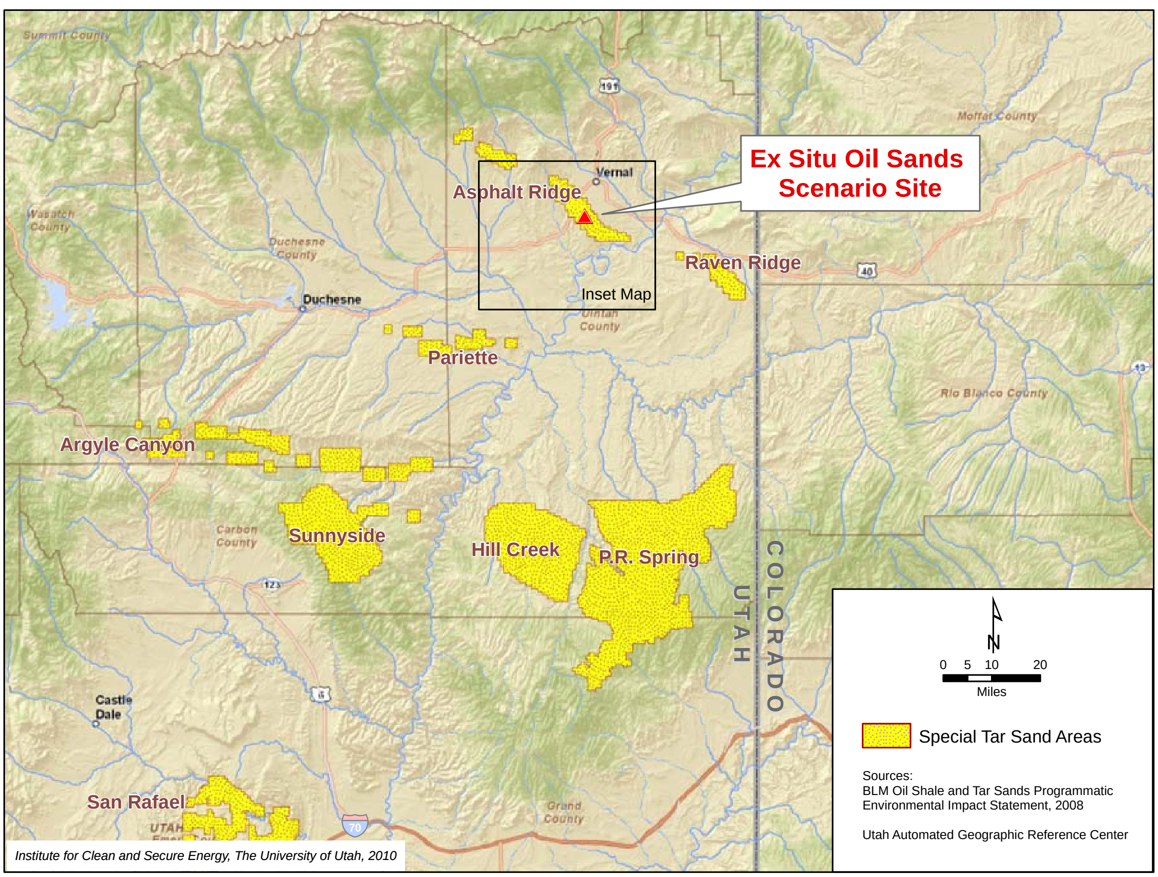

Figure 8.1: Uinta Basin oil sands deposits with location of ex situ oil sands scenario identified.

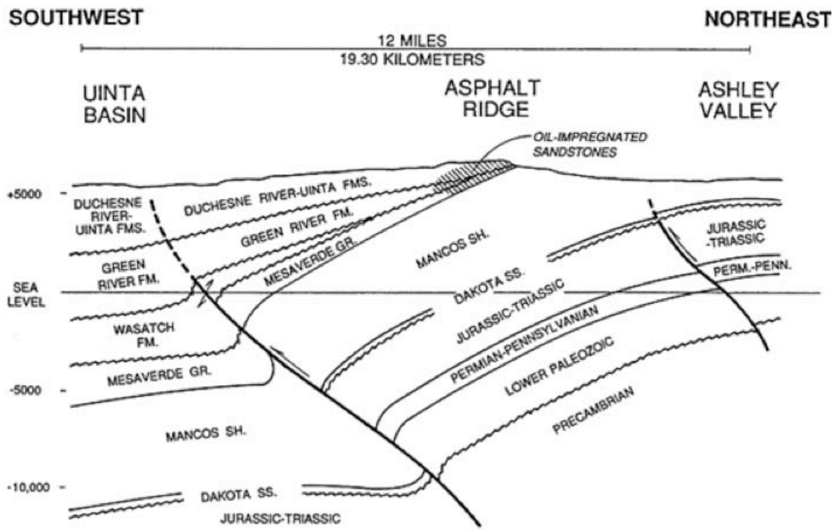

Figure 8.2: Asphalt Ridge oil sands geological structure; from Blackett [1].

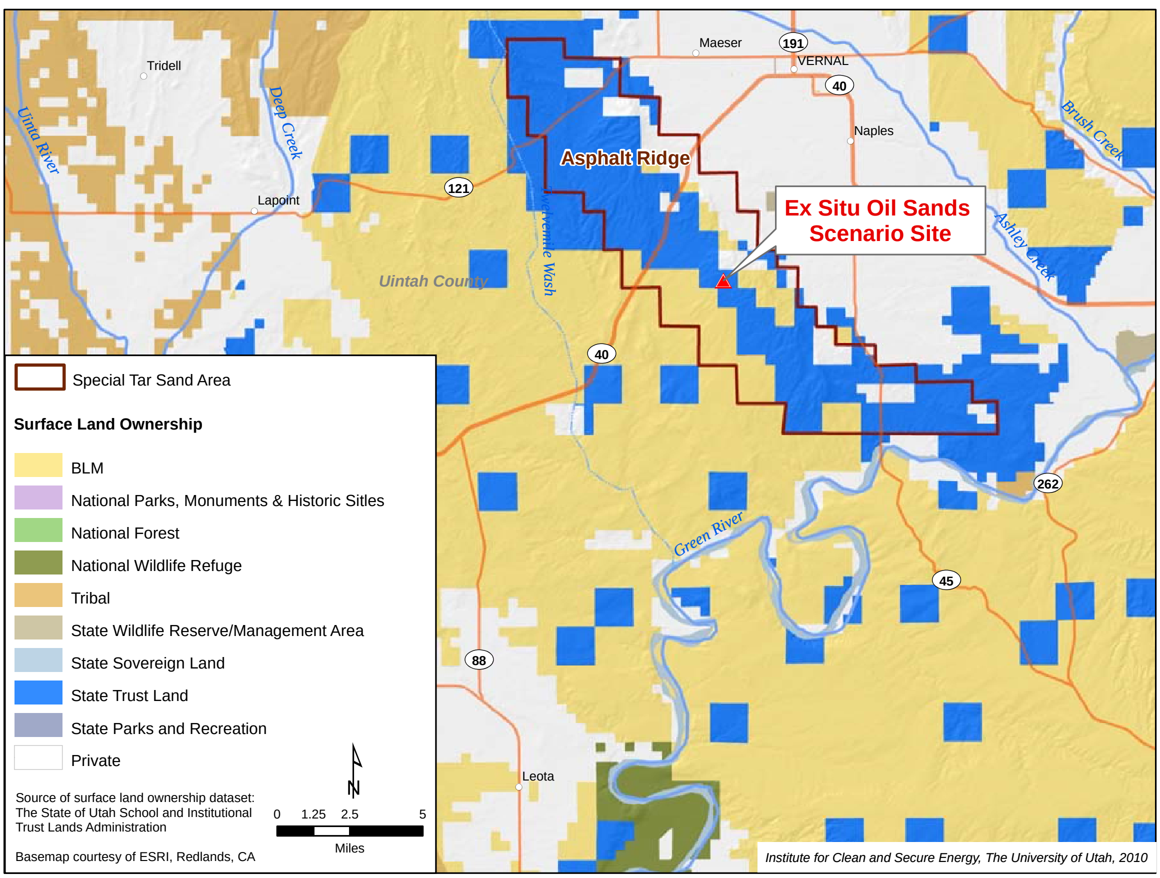

Figure 8.3: Land ownership in the Uinta Basin south of Vernal, Utah, near the ex situ oil sands scenario site.

The bitumen saturation within clastic beds of the Uinta Formation varies both laterally and vertically. Rock type ranges from shale to conglomerate, but in general the most saturated zones are in medium- to coarse-grained sandstone comprised of detrital, poorly sorted quartz and chert and cemented with calcite, hematite and silica [3].

Clastic sedimentary rocks are composed of particles of various sizes of older, weathered rocks. They are classified based on grain size, rock particle types(s), cementing material, and texture [4].

While surface mines in western Canada exploit large, shallow, unconsolidated deposits of oil sands, Utah oil sands are consolidated and the overall size of the resource is several orders of magnitude less (1.7 trillion barrels versus 76 billion barrels OOIP) [6]. Due to the size, quality, and down dip of the oil sands resource on Asphalt Ridge, production capacity is constrained by the economic stripping ratio (SR); see Section 8.1 below. As a result, the assumption for this report is that production is limited to 10,000 BPD.

Detrital particles are fragments of weathered and/or eroded pre-existing rock [5].

8.1 Description of Unit Operations

The overall ex situ oil sands production scenario is shown in Figure 8.4. Heat is supplied by either air-fired or oxy-fired combustion systems. Both systems are shown in Figure 8.4; the dashed lines are for processes that only apply to oxy-firing. Each block in the figure represents a unit operation that is discussed in the following subsections. Unless otherwise noted, all unit operations are located at the scenario site near Vernal, Utah. Figure 8.4 and this analysis provide a general overview of the processes involved in the production of SCO from an oil sands mining/surface processing operation and are not intended to provide an exhaustive list of all unit operations that would be required.

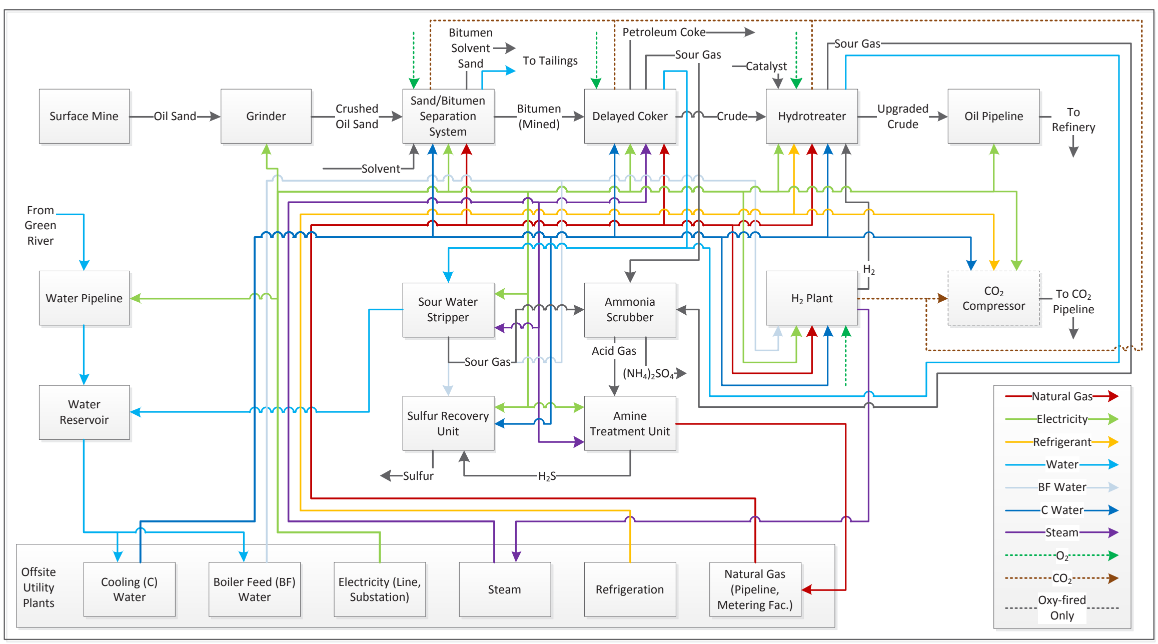

Figure 8.4: Ex situ oil sands production process overview.

8.1.1 Mining

Blackett [1] reports a down-dip angle ranging from 9° to 20° on Asphalt Ridge.

The extraction of oil sands is performed by surface mining. Mining starts from an outcrop on the Asphalt Ridge and proceeds down-dip at an angle of 12° as shown in Figure 8.5. The deposit is assumed to have a uniform bitumen saturation of 10 wt% and a thickness of 60 feet (18.3 meters) along the entire ridge length being mined (4.9 miles or 7.9 kilometers). While Blackett [1] reports a range of 10–135 feet (3.0–41.1 meters) for the deposit thickness in this area, there is a high frequency of thinner deposits noted in similar deposits elsewhere in the Uinta Basin [7], so the assumed presence of a 60-foot contiguous band of oil sands for this scenario is optimistic.

Bitumen saturation is a measure of the bitumen content of the oil sands resource. Bitumen saturation for Utah oil sands range from 0–17 wt% [8,9] with an average value of 8.6 wt% reported for the Northwest Asphalt Ridge area [8] and 10.9 wt% reported for Asphalt Ridge [10].

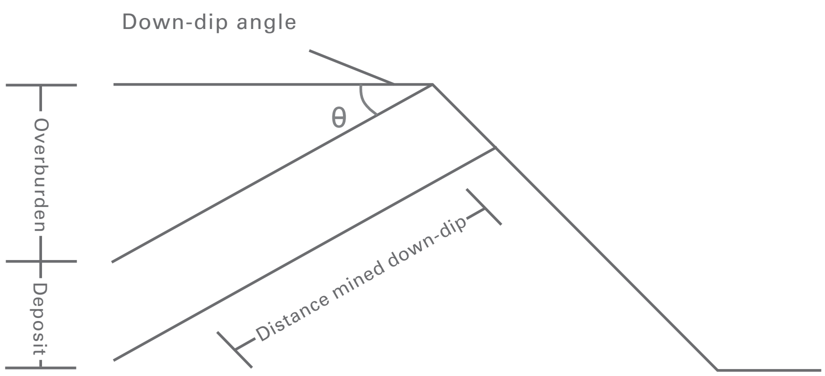

Figure 8.5: Asphalt Ridge mining model.

Overburden above the oil sand deposit is removed and stockpiled for use as a cover for the tailings that are created in the oil sand separation process. Due to the down-dip of the deposit, the amount of surface material removed will increase as the mining moves from the edge of the ridge toward the southwest. In the mining model used for this scenario, mining starts from zero overburden at the edge of the ridge. Then, given the volume of oil sands required to meet production levels, both the distance down-dip as a function of time and the resulting SR are computed.

Stripping ratio (SR) is the amount of overburden (e.g. waste rock) that must be removed to recover the oil sands. An SR = 4 means that 200 feet of overburden must be removed to recover 50 feet of oil sands.

With bitumen as the recovered product, surface mining is only a profitable venture at small values of SR, thus limiting the production capacity of the mine. This mine will continue into the down-dipping deposit until an SR = 4 has been reached, an upper limit based on past experience of other companies who have mined in this area [11].

The bitumen production rate is given by the Equation (8.1):

$$B = \eta\left(\frac{x}{\rho_{bit}(1-x)}\right)\left(\frac{\rho_{ore}H^2L}{t \bullet \sin(\theta)}SR_{\max}\right) \quad \textbf{(8.1)}$$

where B is the bitumen production rate, η is the extraction efficiency of the bitumen/sand separation process, x is the bitumen saturation (wt% bitumen in the oil sands), ρ_{bit} is the density of the bitumen, ρ_{ore} is the oil sand density, H is the thickness of the deposit, L is the length of the mine along the ridge, t is the total time that the mine will be in operation, θ is the down dip-angle, and SR_{max} is the maximum SR that the mine will reach at time t. Table 8-1 lists the values assumed for each parameter for this scenario's base case.

Table 8-1. Mining parameters for ex situ oil sands base case.

km = kilometers

Item	Value	Units	Notes
η	95%	–	Discussed in Section 8.1.3
x	10%	wt%	Range of 6–15 wt% [9]
ρ_{bit}	61.4 (984)	lb/ft^3 (kg/m^3)	API gravity assumed to be 12.0° [12]; value of 12.9° for Asphalt Ridge reported by Baughman [8]
ρ_{ore}	125 (2,000)	lb/ft^3 (kg/m^3)	
H	60 (18.3)	ft (m)	Range of 10–135 ft (3.0–41.1 m) [1].
L	4.9 (7.9)	miles (km)	Maximum length of ridge is 12 miles (19.3 km)
t	20	years	
θ	12°	–	Range of 8°–30° [1]
SR_{max}	4	–	

Using this model for a 10,000 BPD operation, an average constant mining rate of 15,384 TPD (13,956 MTPD) of oil sands is required for the 20-year production life of the project. This average rate takes into account the two-year start up period for the project and the 35 days of maintenance down time per year.

Given the assumptions stated above regarding bitumen content and deposit characteristics, a surface mining cost model was developed based on cost data from InfoMine [13]. The model includes:

- Drilling, blasting and excavating of ore, waste and overburden
- Hauling of ore by truck out of the pit to a mill site
- Hauling of waste and overburden out of the pit to a dump site
- Construction, installation and operation of facilities and equipment necessary for equipment maintenance and repair, electrical systems, fuel distribution, water drainage, sanitation facilities, offices, labs, powder storage, and equipment parts and supply storage
- Tailings disposal
- All labor, material, supply and equipment operating costs.

The Infomine cost data is presented as a function of SR and ore production rate in Table 8-2. This data is converted from metric tons to tons in the analysis that follows. The data points for capital and operating costs given in the table are used in a bilinear interpolation algorithm; costs can thus be determined as a function of any SR and daily ore production rate (within the limits of the data given in the table). In the analysis that follows, production and operating costs are scaled from 2010 to 2012 US$ using the PPI for mining.

8.1.2 Size Reduction and Solids Handling

The mined oil sands are hauled to the grinding unit to reduce the particle size to less than 0.5 inches (1.3 centimeters). This unit operation includes cone crushers for crushing the consolidated sands and a conveyor system to move the crushed sand from the grinding unit to the bitumen recovery process. The capital and operating expenses for the grinding unit and conveyor system are determined using costs given by Seider et al. [14].

The belt for the conveyor system is assumed to have a total length of 0.5 miles (0.85 kilometers) and a width of two feet (0.6 meters).

Table 8-2. Capital and operating costs for a generic surface mining operation from InfoMine [13].

InfoMine collects and publishes an annual report on industry costs for different types of mining operations.

A metric ton is equal to 1000 kilograms or 1.1 tons.

The top number in each entry is the operating cost per metric ton of ore. The bottom number is the total capital cost.

Daily Ore Production (metric tons)	Stripping Ratio (metric tons waste to ore) 1:1	2:1	4:1	8:1
250	$22.82 $3,757,400	$25.77 $4,779,700	$34.93 $6,282,300	$56.77 $8,908,200
500	$16.57 $6,013,100	$24.41 $6,681,800	$32.31 $8,025,400	$47.12 $11,547,600
1,000	$14.33 $6,504,100	$19.04 $8,108,300	$27.00 $11,789,600	$43.34 $18,424,700
2,000	$12.20 $10,524,700	$16.17 $14,642,600	$24.19 $22,396,300	$41.56 $36,973,000
5,000	$7.04 $18,358,500	$9.84 $24,329,800	$14.77 $39,846,600	$26.77 $80,169,800
10,000	$6.27 $30,127,900	$8.53 $42,846,800	$14.19 $88,694,700	$25.41 $168,168,600
20,000	$5.58 $56,761,000	$8.14 $78,963,800	$14.12 $164,062,600	$24.67 $326,833,100
40,000	$5.15 $108,184,000	$7.91 $176,081,600	$12.96 $360,098,100	$24.32 $780,586,200
80,000	$4.04 $203,229,200	$7.82 $453,681,800	$12.95 $769,911,800	$24.20 $1,421,861,200

8.1.3 Bitumen Recovery Process

A water-based bitumen recovery process, similar to the hot water extraction process used for processing Athabascan oil sands, is used to separate the bitumen from the sand. This separation system, shown in Figure 8.6, is modeled using ProMax process simulation software coupled with calculations in an Excel spreadsheet for the hydrocyclone block. The separation system consists of six hydrocyclones running in parallel. A mixture of hot (200°F) water and solvent is mixed with the ground sand and fed into the hydrocyclone train for separation; this slurry flows at a rate of 6,700 gpm (0.423 CMS). Sand exits the hydrocyclone train with a total moisture content of 35 wt% and is sent to a set of dewatering screens which further reduce the sands moisture content to 10 wt% [15]. Damp sands are then sent to tailings disposal without further treatment. The liquid mixture exiting the hydrocyclone train is allowed to separate into an oil phase and an aqueous phase in a decanter. The aqueous phase (hot water and solvent) is recycled back to the hydroclones via a storage tank and the oil phase is sent to a distillation column where the remaining water and the citrus solvent are recovered for recycling. The bitumen leaving the bottom of the distillation column is sent to the upgrader.

The hydrocyclone block is costed according to Seider et al. [14].

After the mixing stage in the Promax simulations, the slurry entering the hydrocyclone train is 65.5 wt% water, 0.2 wt% solvent, 30.6 wt% sand, and 3.7 wt% bitumen.

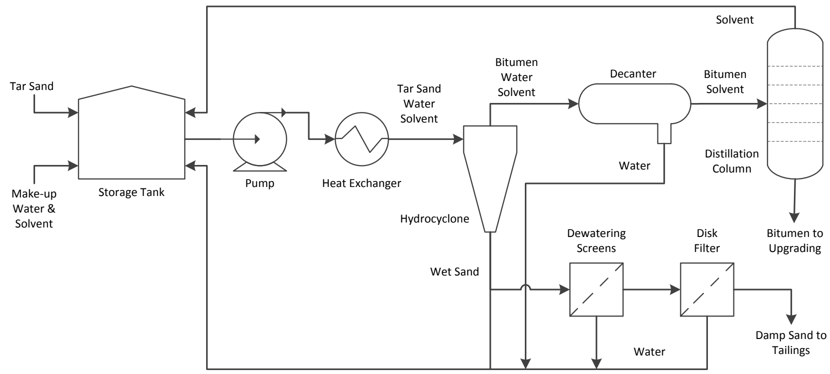

Figure 8.6: Process flow diagram for separation (e.g. bitumen recovery) system.

The overall bitumen extraction efficiency for the separation system is assumed to be 95% based on laboratory data that show bitumen recoveries of greater than 90% using an optimized hot water process for Utah oil sands [16]. Solvent is assumed to remain with the bitumen phase, so solvent loss to the tailings is based on the bitumen content of the tailings. With the assumed bitumen extraction efficiency of 95%, 5% of the incoming solvent leaves with the tailings. Based on ProMax calculations, the separation system recycles 95% of the water and 99.97% of the solvent required for its operation. Overall solvent loss is thus 5.03%.

Capital and operating costs for the separation system are computed from Promax (cyclones, distillation column, pump, heat exchanger, decanter, storage tank) or from data obtained from industrial sources (grinding, conveyor system, dewatering screens, disk filter for fines removal). The costing methodology is described in Section 5.4. It is based on performing a mass and energy balance and then sizing the system and the utility requirements based on this balance.

The source for the grinding and conveyor system costs is Seider et al. [14], for the dewatering screens is Greystone [15] and for the disk filter is Perry and Green [17].

8.1.4 Fractionation and Primary Upgrading

The purpose of primary upgrading is to crack long hydrocarbon chains in the recovered bitumen, forming lighter components. In general, cracking reactions in hydrocarbon chains can be accomplished either thermally or catalytically. Due to its widespread use in industry [12], this scenario employs the thermal cracking process of delayed coking, shown in Figure 8.7, for the primary upgrading of bitumen.

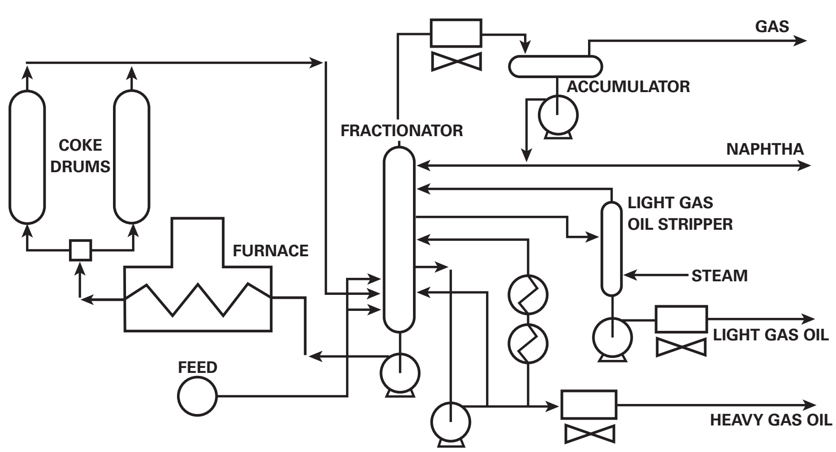

Figure 8.7: Delayed coker process flow diagram from Maples [18].

In the delayed coker unit seen in Figure 8.7, bitumen is first fed to a fractionator where lighter (i.e. lower boiling) components of the bitumen feed are separated from heavier components requiring primary upgrading. These heavier bitumen components are then fed to a natural gas-fired furnace for thermal cracking. The products of the cracking reactions, gas oil and petroleum coke, are pumped into a coking drum where the coke solidifies and the gas oil is driven off as a vapor effluent. Once a drum is filled, steam is fed into the drum to remove residual hydrocarbons in the coke. Finally, the coke is cleared out of the drum using pressurized water. Products (i.e. gas oil vapor) from the coker are then recycled to the fractionator for further separation.

The overall flowrate of bitumen to the delayed coker is 10,822 BPD.

Cracking continues in the mixture as it is transported to and while it is sitting in the drum due to its high temperature (925°F or 496°C).

The lighter components or cuts from the fractionator that comprise the oil product (naptha, VGO, and wax) are processed further in the secondary upgrading step. These distillation cuts are defined as:

- Naptha - hydrocarbons with a boiling range of 100°–400°F (38°–204°C).
- VGO - hydrocarbons with a boiling range of 400°–950°F (204°–510°C).
- Wax - hydrocarbons with a boiling range > 950°F (510°C).

As a commercially proven technology, this primary upgrading unit is modeled based on costing data from Maples [18] using appropriate scaling rules (see Section 5.4.1). The production of CO_2 from coking and O_2 requirements for oxy-firing are both estimated from fuel requirements in the material balances data. Characteristics of the bitumen feed and coker yield are taken from data in Bunger et al. [12] and reproduced below in Table 8-3. The coker yield is assumed to be 82.9 wt% liquid products, 4.8 wt% gaseous products, and 12.3 wt% coke [12]. The gaseous products are captured and used for heating. Coke is collected and sold as fuel coke using price estimates from EIA [19].

This study assumes that the gaseous product is pure methane.

8.1.5 Secondary Upgrading

In addition to primary upgrading, bitumen requires secondary upgrading, e.g. hydrotreating, to reduce its aromatic, nitrogen, sulfur and heavy metal content. In this step, the distillate cuts from the distillation column in the primary upgrading unit (naptha, VGO, and wax) are hydrotreated separately in catalytic reactors. While the hydrotreating process is the same as for the ex situ oil shale scenario (described in Section 6.1.6), the inputs are different. The total flowrate of oil (e.g. distillate cuts) to the hydrotreater is 8,966 BPD. Due to the reduced production rate and the differences in sulfur and nitrogen content of raw bitumen as compared to raw shale oil, 1,738 tons (1,570 metric tons) of H_2S and 2,710 tons (2,450 metric tons) of NH_3 are produced annually as byproducts of hydrotreating.

The hydrotreater is modeled with ProMax using properties of the distillate cuts from the primary upgrading step (see Table 8-3). With the detailed process flowsheet information provided by the simulation, the method of Guthrie (see section 5.4.1) is used to compute capital and operating costs. Hydrogen needed for hydrotreating is provided by the hydrogen plant.

The properties of the raw and upgraded bitumen are given in Table 8-3; properties of three benchmark crudes are shown for comparison. The product of the primary upgrading step is labeled "Coker Yield." The upgraded bitumen

("Hydrotreater Yield") is of high quality with properties similar to those of the benchmark crudes, including 30°API, low pour point, and low sulfur, nitrogen, and heavy metal content.

Table 8-3. Properties of raw bitumen and upgraded SCO in comparison to three benchmark crudes [12, 20–22].

		Raw Bitumen	Coker Yield	Hydrotreater Yield	West Texas Intermediate	Brent Crude	Arabian Light
Oil Properties	API Gravity	12.0	25.8	31.68	39.6	38	34
	Sulfur (wt%)	0.42	0.32	0.0023	0.24	0.37	1.7
	Nitrogen (wt%)	1.03	0.58	0.05		0.1	0.07
	Pour Point (°F)				-18	45	-10
	Solids (wt%)						
Distillate Cuts	Boiling Range (°F)	(vol %)					
Naptha	100 - 400	0.5	14.2	20.3	56		
	104 - 800					78	67
Vacuum Gas Oil	400 - 950	44.7	70.2	71.3	32		
	800 +					21.7	32
Wax	950 +	54.8	15.6	8.4	9		
	1000 +					10.2	17

8.1.6 Hydrogen Plant

The quantity of H_2 needed for the secondary upgrading of bitumen is determined from the following mass balance:

$$m = m_H + m_S + m_N \tag{8.2}$$

where m is the total mass of H_2 required per barrel and each m_i is the mass of H_2 required to account for the change in the hydrogen (H), sulfur (S), and nitrogen (N) content of the hydrotreater feed [12] and product [20]. Each component is calculated on a per barrel basis as follows:

$$m_H = \rho x_H + \rho_o x_{H_o} \tag{8.3}$$

$$m_S = a(\rho_o x_{S_o} - \rho x_S)\frac{M_H}{M_S} \tag{8.4}$$

$$m_N = a(\rho_o x_{N_o} - \rho x_N)\frac{M_H}{M_N} \tag{8.5}$$

where x_i is the mass fraction of species i, ρ is density, a and b are stoichiometric coefficients based on the reaction given in Equation (6.3), M_i is the molecular weight of species i, and the subscript o refers to the hydrotreater feed. Based on this mass balance, it is estimated that 412 SCF (11.7 cubic meters) of H_2 per barrel of raw bitumen are required. For comparison, the shale oil produced from the ex situ oil shale process requires 2,000 SCF (57 cubic meters) of H_2 per barrel of shale oil.

The H_2 is supplied by a hydrogen plant of the same design as discussed in section 6.1.7. However, it is substantially smaller due to the lower production rate of oil for this scenario. The hydrogen plant is supplied with natural gas and steam for both the steam reformer and the water gas shift reactor.

The capital and operating costs for the hydrogen plant are determined by applying the economic and engineering scaling factors discussed in Section 5 to capital and utilities utilization data for a PSA-based H_2 production system from Fleshman [23]. The excess steam produced by the plant is sold back to the off-site steam utility at 50% of the cost of purchasing high pressure steam.

The entire ex situ oil sands production/upgrading process requires 939 million pounds (426 million kilograms) of steam and produces 284 million pounds (129 million kilograms) of steam per year.

8.1.7 Ammonia Scrubber

Sour gases generated as byproducts in the hydrotreater are fed to a wet scrubber with dilute sulfuric acid to remove NH_3 as described in Section 6.1.8. Capital and operating expenses as well as ammonium sulfate sales are neglected in the cash flow analysis.

Ammonium sulfate production is estimated to be 10,511 tons (9,536 metric tons) annually.

8.1.8 Amine Treatment Unit

The amine treatment unit scrubs acid gas, e.g. H_2S, from the waste gas streams as described in Section 6.1.9. Capital and operating costs are scaled from data in Maples [18]. See Figure 8.4 for an overview of how this unit is integrated with the ammonia scrubber, sulfur recovery unit and sour water stripper.

8.1.9 Sulfur Recovery Unit

Acid gas streams are further stripped of H_2S in the sulfur recovery unit as described in Section 6.1.10; the product, elemental sulfur, is produced at a rate of 1,635 tons (1,483 metric tons) per year. Capital and operating costs are scaled from data in Maples [18], a sulfur recovery rate of 95 wt% is assumed, and all sulfur recovered is sold at market prices [24].

8.1.10 Sour Water Stripper

Fouled water from the fractionator and recycled cooling water from the hydrotreater (see Figure 8.4) is processed through a sour water stripper to remove dissolved contaminants as described in Section 6.1.11. The stripped water is then sent to the water reservoir (see Section 8.2.4) for reuse. Capital and operating costs are scaled from data in Maples [18].

8.1.11 Delivery via Pipeline

The SCO is taken from product storage tanks at the upgrader and sent through a pipeline from the mine site near Vernal, Utah to North Salt Lake City. The pipeline path is shown in Figure 6.10. The total estimated pipeline length is 152 miles (245 kilometers).

An economical pipeline diameter of 4.4 inches (11 centimeters) was computed by optimizing the pumping requirements and costs using the method of Peters and Timmerhaus [25]. The capital costs for constructing the pipeline and pumping stations are estimated following the methodology used by Boyle [26]. Additional details about the pipeline are found in Section 6.1.12.

8.1.12 Cost of Utilities

The utilities required for this ex situ oil sands scenarios are listed in Table 5-7: natural gas; electricity; process, cooling and boiler feed water; chemicals; steam; O_2; and refrigerant. With one exception, this scenario employs the constant utility prices in Table 5-7. The exception is the profitability analysis using the NPV method, which uses EIA price forecasts to estimate not only oil sales but also natural gas and electricity prices [27].

Natural gas and electricity are brought in to the site from Vernal, Utah, a distance of approximately 5.3 miles (8.5 kilometers). Water for plant needs is pumped 5.6 miles (9 kilometers) from the Green River via pipeline to a reservoir at the plant site. Raw water from the reservoir (see Section 8.2.4) is treated such that it is suitable for use as process, cooling, and boiler feed water. The chemicals for water treatment and other purposes are trucked in and stored in a warehouse.

Three other required utilities, namely steam, refrigeration, and O_2 (for oxy-fired processes), are purchased from off-site utility plants at the per unit cost given in Table 5-7. Other than capital costs for construction, these prices are assumed to cover all of the costs/externalities of the utilities. Capital costs for constructing the steam, water treatment and refrigeration plants are estimated from Seider et al. [14] and are listed in Table 5-5 under allocated costs for utility plants. Capital costs for the oxygen plant are excluded due to lack of data.

Infrastructure costs associated with bringing utilities to the site are accounted for in various ways. Costs associated with (1) building an electrical substation ($1.5 million), (2) establishing the electrical line, switching gear, and tap ($2.3 million), and (3) bringing in the natural gas line ($5.6 million) and establishing the metering hub ($1.0 million) have been obtained from Sage Geotech [28]. The costs of the water pipeline ($4.0 million) and the water reservoir ($4.3 million) have been estimated using standard construction and excavation cost estimation methods [26, 29]. Warehousing costs of chemicals are accounted for in the percentage (10%) of C_{TBM} used for service facilities [14]; see Table 5-5.

Costs given here are for the air-fired case. For oxy-firing, the cost of the electrical substation increases to $2.2 million and the water reservoir to $4.4 million.

8.1.13 Labor Utilization

Skilled and maintenance labor as well as management are required for all aspects of ex situ oil sands production. The number of employees on a per shift basis is determined for each unit operation of the entire production process as listed in Table 8-4. Assuming that five shifts per week are used for 24/7 operation, the total number of employees for the air-fired scenario ranges from 550–655, depending on the SR of the mine. As the mine moves farther down dip (e.g. higher SR), more employees are required. For oxy-firing, the total number of employees ranges from 585–690. The number of people employed to perform maintenance labor is excluded from the totals in Table 8-4. Instead, the costs of maintenance labor are assumed to be covered by the yearly maintenance cost (5% of C_{TDC}).

Mining labor requirements are extrapolated based on data obtained from InfoMine [13] as shown below in Table 8-5. Labor costs are included in the operating costs given in Table 8-2. Labor requirements for all other unit operations are estimated following the approach given by Seider et al. [14], but uncertainty in the methodology means that actual labor requirements could be quite different from those predicted here.

Table 8-4. Labor requirements for ex situ oil sands extraction (per shift).

These labor requirements are for the startup and production phases of the project and do not include labor required for construction of the various unit operations.

Process	Operators	Lab & Engineering	Management
Surface Mine	18 - 37	---	3 - 5
Extraction	16	2	1
Delayed Coker	14	2	1
Hydrotreater	18	2	1
H_2 Plant	6	2	1
Sour Water Stripper	4	2	1
Amine Treatment Unit	4	2	1
Sulfur Recovery Unit	6	2	1
Total	**86 - 105**	**14**	**10 - 12**
Oxy-Fired Only			
CO_2 Compressor	4	2	1
Total	**90 - 109**	**16**	**11 - 13**

Table 8-5. Total number of hourly and salary employees for surface mining from InfoMine [13].

	Stripping Ratio			
Ore Production Rate (MTPD)	**1:1**	**2:1**	**4:1**	**8:1**
250	14	15	18	29
500	15	24	28	37
1,000	32	41	45	60
2,000	47	55	70	97
5,000	55	67	80	129
10,000	78	87	146	225
20,000	135	197	299	404
40,000	219	296	432	780
80,000	325	501	854	1,669

8.2 Environmental Aspects of Ex Situ Oil Sands Scenario

This profitability analysis does not include the cost of externalities associated with visual impairment, effects on ground and surface water quality, the reallocation of a large land surface area for industrial use, or the treatment and storage costs for waste streams other than sand tailings. This analysis does account for the costs of some air pollution control, the disposal of sand tailings, carbon management, and water management as described below.

8.2.1 Air Pollution Control

This scenario includes the costs of removing H_2S from the various sour gas streams generated by the upgrading of oil sands bitumen; see Sections 8.1.8 and 8.1.9. Capital and operating expenses for removing NH_3 are assumed to be offset by the sale of ammonium sulfate; see Section 8.1.7. All other capital costs for air pollution control equipment are assumed to be covered by this scenario's contingency cost, which is $76.7 million.

8.2.2 Treatment and Storage of Sand Tailings

The production process outlined in this scenario does not produce tailings ponds like those seen adjacent to ex situ oil sands operations in Canada [30]. However, it does produce damp sand tailings at the average rate of 15,601 TPD (14,153 MTPD); overburden is also produced at a rate equal to the tailings production rate multiplied by the current SR (an average rate of 30,767 TPD or 27,912 MTPD). Hence, on average, 46,368 TPD (42,065 MTPD) of material must be disposed of on 1,977 acres (800 hectares) of the tract surface. The required surface area is scaled based on the information about spent shale disposal in Section 6.2.2.

The sand tailings are assumed to contain 90 wt% sand, 10 wt% water, and trace amounts of bitumen and solvent.

Scaling is linear based on mass of material for disposal.

The cost of disposing of these tailings is included in the InfoMine cost model described in Section 8.1.1. However, reclamation costs are not included in the cost model nor in the analysis presented in this section.

8.2.3 Carbon Management

As with the ex situ oil shale scenario, two different combustion systems are considered to supply heat for the various unit operations: conventional (air-fired) combustion and oxy-combustion. Two cases are considered for the conventional combustion system: (1) no tax on CO_2 and (2) a $25 per ton tax on CO_2. The oxy-combustion system produces a nearly pure CO_2 stream that is compressed to pipeline conditions and sold at a price of $25 per ton.

The equipment for the combustion system is costed in ProMax and then rolled into the cost reported for the hydrotreater. The costs for CO_2 compression are determined from a regression fit of costs for compressor systems at various scales; see Section 6.2.3 for additional details. The O_2 required for oxy-firing is purchased from a supplier at the price per ton listed in Table 5-7. The costs of a CO_2 pipeline are assumed to be the responsibility of the purchaser and are not included in the present analysis.

For both the air- and oxy-fired cases, GHG emissions (including CO_2, CH_4, and N_2O) are produced from: mining and transport of the sands; heating and electricity associated with the extraction/separation system, the delayed coker, the hydrogen plant, and the hydrotreater; product transport to the refinery; and the air separation unit that produces O_2 for the oxy-fired case. For the air-fired combustion system, CO_2e emissions from these sources total 427,100 tons (388,300 metric tons) per year. For the oxy-combustion system, 258,000 tons (234,000 metric tons) CO_2e are emitted per year and 278,000 tons (252,200 metric tons) of CO_2 are produced per year of a quality that can be sold to a pipeline. These totals neglect GHG emissions associated with construction of the facilities, refrigeration, and water treatment.

8.2.4 Water Management

As with the oil shale scenarios, each part of the oil sands production process either generates water, consumes water, or is water neutral as a result of recycling; see the generic water balance shown in Figure 6.12. Water usage for this oil sands scenario is estimated using a material balance around the entire scenario. Water losses from the scenario include evaporation in the cooling towers, moisture in the sand tailings, and consumption for H_2 production.

A material balance applies the law of conservation of mass to a physical system such as the ex situ oil sands scenario. It accounts for water and other material entering and leaving the system.

Table 8-6 summarizes water usage for both the air- and oxy-fired ex situ oil sands scenarios. The process units listed in the "Recycled" category do not consume water but rather use it as a heat transfer medium. Water flow rates for these units are determined from process flowsheet calculations in ProMax (bitumen recovery, hydrotreater and CO_2 compressor) or scaled from literature values (Maples [18] for the sulfur recovery unit and Fleshman [23] for the hydrogen plant). Water leaving these process units is sent to cooling towers before it is recycled. The total required makeup water for the air-fired case is 1,316 acre-feet per year (1.82 CFS or 0.0515 CMS). For the oxy-fired case, this number increases slightly to 1,324 acre-feet per year (1.83 CFS or 0.0518 CMS) due to the larger cooling water demand for the CO_2 compressor system, which leads to increased recycle losses.

Table 8-6. Itemized water balance for ex situ oil sands production with air- and oxy-firing; data obtained from various sources [18,23,31,32] and from Promax simulations.

This table does not include water needed for reclamation.

Category	Item	Water (bbl / bbl of oil)		Water (acre-ft/yr)	
		Air-Fired	Oxy-Fired	Air-Fired	Oxy-Fired
Recycled	Cooling Water				
	Bitumen Recovery	19.61	19.61	9,224	9,224
	Delayed Coker	0.03	0.03	12	12
	Hydrotreater	0.12	0.12	57	57
	H_2 Plant	0.46	0.46	214	214
	Sulfur Recovery Unit	0.05	0.05	21	21
	CO_2 Compressor	-	12.42	-	5,842
	Boiler Feed Water				
	Sulfur Recovery Unit	0.01	0.01	3	3
	Steam	0.74	0.74	346	346
	Subtotal	**21.00**	**33.41**	**9,878**	**15,720**
Consumed	Surface Mine	1.55	1.55	731	731
	Tailings/Sand	1.03	1.03	487	487
	H_2 Plant	0.16	0.16	76	76
	Upgrading				
	Cooling Tower Makeup	0.03	0.40	12	187
	Steam Recycle Losses	0.02	0.02	10	10
	Subtotal	**2.80**	**3.17**	**1,316**	**1,491**
Generated	CO_2 Compressor	-	0.36	-	168
	Subtotal	**-**	**0.36**	**-**	**168**
Water In		**2.80**	**2.81**	**1,316**	**1,324**

The largest water use in this scenario ("Consumed" category) is for the surface mine, which includes mining, ore handling, and dust control. Surface mine water use is estimated by linearly scaling water use data for underground oil shale mining [31] based on the average amount of material mined (includ-

Water usage information was not available in the InfoMine data [13].

ing both tar sands and overburden). Moisture remaining in the sand tailings sent for disposal, assumed to be 10 wt%, represents the second largest water use; approximately one barrel of water is lost for each barrel of oil produced.

The hydroclones and dewatering screens recycle approximately 18.6 of the 19.6 barrels of water per barrel of oil used in the extraction system.

Water is also consumed in other process units. A small amount of water in the form of steam is consumed as a reactant in the hydrogen plant. A minor water loss (3 wt% of the "Recycled" water stream) results from evaporation in the cooling towers, listed as "Cooling Tower Makeup" in Table 8-6. In the upgrader, there are evaporative losses from the cooling towers, listed as "Cooling Tower Makeup" in Table 8-6, and steam recycle losses, which are estimated to be 3% by volume for steam generation in a closed cycle loop. Other small water uses/losses are assumed to be negligible and are not included in the water accounting. Also, the volume of water required for the one-time filling of tanks for startup is not included in Table 8-6.

See Table B.6.1.1 in the Connacher report [32] for estimated steam recycle losses for a new SAGD facility.

Water in the "Generated" category is produced during the condensation of oxy-fired flue gases. The volume of condensed water produced is calculated based on the mass flow rate of CO_2 and assumptions of complete combustion and recovery of all water in the flue gases.

The main source of water near Asphalt Ridge is the Green River. Monthly average flow rates for the Green River are shown in Figure 8.8 based on data from USGS [33]. The Green River's 65-year average daily flow rate in September (lowest flow month) is 1,910 CFS (54.1 CMS). Hence, the makeup water flow rate represents less than 0.1% of the Green River flow at its lowest average flow rate.

This flowrate is measured near Jensen, Utah, the nearest upstream USGS monitoring site from Asphalt Ridge.

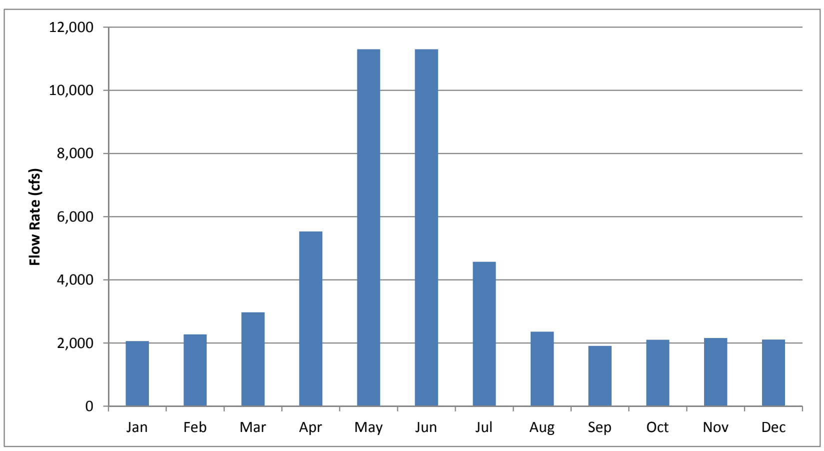

Figure 8.8: Average historical discharge from the Green River by month near Jensen, Utah [33].

The bitumen extraction and upgrading processes require water on a daily basis plus a one-time filling of tanks for startup. For this scenario, water is purchased at a rate of $50 per acre-foot per year (see Table 5-7) from those with agricultural water rights [34]. The purchased water is diverted or pumped from the Green River and transferred via a short water pipeline to the plant site to fill the water storage reservoir for daily use. The capital and operating costs for the water pipeline are included in this analysis.

The size of the reservoir is determined by the duration of a prolonged drought in the area (90 days; see Section 6.2.4) and the total water utilization for air-fired and oxy-fired processes (see Table 8-6). The estimated reservoir sizes are 322 acre-feet (0.400 million cubic meters) for the air-fired case and 326 acre-feet (0.403 million cubic meters) for the oxy-fired case. Costs for the lined water reservoir are computed using construction excavation costs that are applicable in the Uinta Basin [29]; they are estimated to be $4.3 million for the air-fired and $4.4 million for the oxy-fired ex situ oil sands operations.

8.3 Profitability Analysis of Ex Situ Oil Sands Production

All dollar values given in this section are reported as 2012 US$ unless otherwise noted. An inflation rate of 1.8% is used to adjust dollar values from other reports to 2012 US$, except for instances where more specific inflation indices are available.

The profitability analysis performed for this scenario is the same as that outlined in Section 6.3: an estimation of capital costs, a "base case" Supply Price Method profitability analysis as a function of hurdle rate, an NPV profitability analysis based on EIA oil price forecasts and defined hurdle rates, and a Supply Price Method sensitivity analysis. Both the Supply Price Method and the NPV Method consider all the costs associated with SCO production as described in Section 5.4. Bitumen production costs at the mine site (excluding upgrading and transportation costs) are also included for comparison. All costs and profitability measures are reported in terms of real dollars.

Table 8-7 lists the key assumptions for the base ex situ oil sands cases using air-fired and oxy-fired combustion for plant heating. For the air-fired production scenario, all of the process heat is supplied by air-fired combustion of purchased natural gas supplemented by methane-rich streams from the delayed coker. For the oxy-fired production scenario, all of the process heat is supplied by oxy-fired combustion of natural gas supplemented by the same methane-rich streams.

Table 8-7. Ex situ oil sands scenario base case assumptions.

Category	Input/assumption
Air- & oxy-fired	
Bitumen saturation	10 wt%[a]
Bitumen recovery	Separation system - 95 wt% [10], Coker - 82.85 wt% [12], Hydrotreater - 98.1 wt% (from ProMax flowsheet)
Utility pricing	Fixed prices from Table 5-7
Hurdle Rate	0–12%
Taxes and Royalties	Federal: 35% of Taxable Income State: 5% of Taxable Income Property: 1% of Total Permanent Investment Severance[b]: 3–5% of Adjusted Wellhead Price Conservation Fee: 0.2% of Adjusted Wellhead Price Oil Royalty[b]: 8–12.5% of Oil Sales
Product	WTI-quality SCO
Air-fired	
CO_2 tax	None
Revenue	Oil, coke, sulfur, and steam
Oxy-fired	
CO_2 sales	$25/ton
Revenue	Oil, CO_2, coke, sulfur, and steam

[a] *Other assumptions for mining parameters are found in Table 8-1.*
[b] *See Section 5.4.3 for scenario accounting details related to tax and royalty rates.*

Table 8-8 lists the major outputs from and inputs to the ex situ production of SCO from oil sands on a per barrel basis. The CO_2 output from the oxy-fired scenario has been captured, is of pipeline-quality, and can be sold while the CO_2 from the air-fired scenario is dilute and is emitted into the atmosphere from a smokestack. On the inputs side, water usage is similar to that for the Paraho Direct ex situ oil shale scenario and half that of the Tosco II ex situ oil shale scenario. The per barrel inputs and outputs are very similar between the air-fired and oxy-fired systems. The oxy-fired system does requires more electricity due to the power consumption of the CO_2 compression system and O_2 must be purchased.

Table 8-8. Major process output and inputs on a per barrel basis.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	5.76	5.76	lb
	CO_2[a]			
	Emitted to Atmosphere	253	150	lb
	Sold to Pipeline	-	152	lb
	Steam (600 psig, 700°F)	78	78	lb
	Petroleum Coke	46	46	lb
	Sulfur	0.85	0.85	lb
	Tailings [b]	9,274	9,274	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	17.89	25.42	kWh
	Fuel [c]			
	Purchased	0.91	0.89	MMBtu
	Total	1.39	1.38	MMBtu
	Makeup Water	2.80	2.81	bbl
	O_2	-	179	lb
	Refrigerant	13.58	13.58	MJ
	Solvent	0.16	0.16	gal
	Steam			
	50 psig	332	332	lb
	450 psig	383	383	lb

[a] *The per barrel CO_2 output is CO_2e, and these emissions do not include construction of the facilities, refrigeration, or water treatment.*
[b] *Tailings includes both overburden and wet sand. Quantity reported here is for the average SR = 2.*
[c] *The fuel input refers to natural gas only. Difference between the amount of fuel purchased and the fuel total is the captured heating value of gases from the delayed coker.*

8.3.1 Capital Costs for Ex Situ Oil Sands Extraction

The total capital investment for the complete air-fired plant is \$818 million; that of the oxy-fired plant is \$848 million. A breakdown of all capital costs is shown in Table 8-9; definitions for all cost categories can be found in Section 5.3.4. The largest capital costs for the air-fired heating system are for the hydrotreater (16%), bitumen separation system (13%), and mine (8%). These percentages are only slightly changed for the oxy-fired case.

The CPFB is \$81,787 for the air-fired case and \$84,765 for the oxy-fired case. These numbers can be compared to the estimated capital costs of integrated mining, extraction, and upgrading oil sands projects in Canada published in a 2008 CERI report [35]. The CPFB for the four commercial operations listed in the report ranges from \$86,958–\$137,372 with an average of \$108,676. Production rates for these operations range from 60,000–140,000 BPD of SCO. Hence, the CPFB estimates for this ex situ oil sands scenario are at the very low end of CPFB estimates for the much larger scale Canadian projects.

CERI reports numbers in C\$. To convert to US\$, an exchange rate of 1:1 is assumed. Numbers have also been adjusted to 2012 US\$ using the CEPCI index.

Table 8-9. Capital cost breakdown by unit for the base case ex situ oil sands scenario in millions of 2012 US\$.

Category	Item	Air-fired	Oxy-fired
Total Bare Module Investment - C_{TBM}	Surface Mine	\$ 69.4	\$ 69.4
	Bitumen Recovery	\$ 102.9	\$ 102.9
	Delayed Coker	\$ 62.7	\$ 62.7
	Hydrotreater	\$ 124.2	\$ 124.2
	H_2 Plant	\$ 12.7	\$ 12.7
	Sour Water Stripper	\$ 6.5	\$ 6.5
	Amine Treatment Unit	\$ .5	\$ .5
	Sulfur Recovery Unit	\$ 1.4	\$ 1.4
	CO_2 Compressor	\$ -	\$ 11.4
	C_{TBM} Subtotal	**\$ 380.2**	**\$ 391.7**
Total Direct Permanent Investment - C_{DPI}	Site Preparation	\$ 31.1	\$ 32.2
	Service Facilities	\$ 31.1	\$ 32.2
	Oil Pipeline	\$ 44.3	\$ 44.3
	Water Pipeline	\$ 4.0	\$ 4.0
	Water Reservoir	\$ 4.3	\$ 4.4
	Allocated Costs for Utility Plants	\$ 16.3	\$ 18.3
	C_{DPI} Subtotal	**\$ 511.3**	**\$ 527.1**
Total Depreciable Capital - C_{TDC}	Contingency	\$ 76.7	\$ 79.1
	C_{TDC} Subtotal	**\$ 588.0**	**\$ 606.2**
Total Permanent Investment - C_{TPI}	Land	\$ 11.8	\$ 12.1
	Permitting	\$ 6.4	\$ 6.4
	Royalties for Intellectual Property	\$ 11.8	\$ 12.1
	Startup	\$ 58.8	\$ 60.6
	Investment Site Factor	1.15	1.15
	C_{TPI} Subtotal - US Midwest	**\$ 778.2**	**\$ 802.0**
Total Capital Investment - C_{TCI}	Working Capital	\$ 39.6	\$ 45.7
	Total (\$)	**\$ 817.9**	**\$ 847.7**

A 1987 report by Oblad and coworkers at the University of Utah states that "Tar sand economics depend on a wide variety of factors, including site specific resource characteristics; location of the resource relative to utilities, roads, pipelines, and population centers; mining methods employed; and recovery and upgrading technologies" [10]. The authors summarize results of an economic analysis of SCO production from Utah bitumen by Wells et al. [36]. The base case assumes an integrated surface recovery/upgrading plant with a capacity of 20,000 BPD. The mine SR = 4 and the average bitumen saturation of the ore is 8 wt%. The plant includes a water-assisted bitumen recovery process followed by coking and then hydrotreating of the coker yield. Table 8-10 compares the capital cost breakdown in this report with that from Oblad et al. [10], which has been scaled from 1984 US\$ to 2012 US\$ using the CEPCI index. Because of the different cost estimating methodologies used, it is not possible to provide a direct comparison for all cost categories.

Table 8-10. Comparison of capital cost breakdown by unit for base case ex situ oil sands scenario in millions of 2012 US$ as reported by Oblad et al. [10] and as computed in this report.

Aggregated cost categories from Oblad et al. [10] are described in the footnotes.

Category	Item	Oblad 20,000 BPD	Air-Fired 10,000 BPD
Total Bare Module Investment - C_{TBM}	Surface Mining [a]	$ 83.8	$ 69.4
	Bitumen Recovery [b]	$ 100.3	$ 102.9
	Upgrading [c]	$ 279.7	$ 208.0
	C_{TBM} Subtotal	**$ 463.8**	**$ 380.2**
Total Direct Permanent Investment - C_{DPI}	Site Preparation [d]	$ 9.5	$ 31.1
	Service Facilities [e]	$ 65.6	$ 31.1
	Oil & Water Pipeline	$ 58.5	$ 48.3
	Water Reservoir		$ 4.3
	Allocated Costs for Utility Plants [f]	$ 175.4	$ 16.3
	Other [g]	$ 7.9	
	C_{DPI} Subtotal	**$ 780.6**	**$ 511.3**
Total Depreciable Capital - C_{TDC}	Contingency		$ 76.7
	C_{TDC} Subtotal	**$ 780.6**	**$ 588.0**
Total Permanent Investment - C_{TPI}	Land		$ 11.8
	Permitting		$ 6.4
	Royalties for Intellectual Property		$ 11.8
	Startup		$ 58.8
	Investment Site Factor		1.15
	C_{TPI} Subtotal - US Midwest	**$ 780.6**	**$ 778.2**
Total Capital Investment - C_{TCI}	Working Capital	$ 9.5	$ 39.6
	Total ($)	**$ 790.1**	**$ 817.9**

[a] *Predevelopment mine costs, mine capital costs*
[b] *Crushing, conditioning, flotation, separator, solvent treatment, solids removal, sand disposal, solvent recovery*
[c] *Coker, hydrotreater, steam reformer (i.e. hydrogen plant)*
[d] *Roads*
[e] *Storage tanks, buildings*
[f] *Utilities module, electric generation, electric lines*
[g] *Socioeconomic impact mitigation*

The scaled C_{TCI} reported in Oblad et al. is $790 million (CPFB of $39,506) compared to the present estimate of $818 million (CPFB of $81,787), due primarily to the difference in the amount of overburden removed and ore processed as determined by production scale (20,000 BPD versus 10,000 BPD), quality of ore (8 wt% versus 10 wt% bitumen), and overburden removal required (SR = 4 versus SR = 0 increasing to SR = 4). However, the greatest discrepancy is in "Allocated Costs for Utility Plants," which is due not only to scale but also to a different process design in Oblad et al. [10] (as summarized from Wells et al. [36]) that calls for the construction of a coke-fired electrical generating facility.

8.3.2 Supply Price Evaluation of Ex Situ Oil Sands Base Case

The supply price at a specified hurdle rate is computed by finding the real fixed price that results in NPV = 0 with the discount factor computed from the hurdle rate; see Section 5.2.2 for additional details.

8.3.2.1 Base Case Supply Prices

The base case supply price as a function of hurdle rate is given in Table 8-11 for air-fired combustion and in Table 8-12 for oxy-fired combustion. The tabulated supply costs from Tables 8-11 and 8-12 are plotted in Figures 8.9 and 8.10, respectively. All supply costs listed in Tables 8-10 and 8-11 are positive contributors to the supply price while all non-oil revenue streams are negative contributors.

See Section 5.2.2 for details on how supply price is determined.

Table 8-11. Supply price for air-fired ex situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine [a]	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31
Bitumen Recovery	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ 7.62
Upgrading [b]	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38	$ 15.38
Taxes	$ 6.58	$ 8.20	$ 10.14	$ 12.42	$ 15.24	$ 18.51	$ 22.42
Oil Royalties	$ 8.02	$ 8.55	$ 9.18	$ 9.92	$ 10.80	$ 11.81	$ 13.01
Net Earnings	$ -	$ 2.77	$ 6.08	$ 9.97	$ 14.52	$ 19.74	$ 25.77
Maintenance	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17	$ 8.17
Other [c]	$ 13.81	$ 13.85	$ 13.89	$ 13.94	$ 13.99	$ 14.06	$ 14.13
Supply Cost	**$ 76.90**	**$ 81.85**	**$ 87.78**	**$ 94.74**	**$ 103.05**	**$ 112.61**	**$ 123.82**
Other Revenue	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41	$ 1.41
Oil Supply Price	**$ 75.50**	**$ 80.44**	**$ 86.37**	**$ 93.33**	**$ 101.65**	**$ 111.21**	**$ 122.42**

[a] "Mine" includes costs for mining and size reduction/solids handling (e.g. crushing).
[b] "Upgrading" includes all costs associated with the delayed coker, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.
[c] "Other" includes all costs associated with the oil pipeline, water pipeline, allocated costs for utility plants, water reservoir, site preparation, service facilities, contingency, permitting, research, administration, incentive compensation, insurance, intellectual property royalties, overhead, land, startup, and CO_2 compressor (oxy-firing only).

Table 8-12. Supply price for oxy-fired ex situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31
Bitumen Recovery	$ 9.89	$ 9.89	$ 9.89	$ 9.89	$ 9.89	$ 9.89	$ 9.89
Upgrading	$ 19.27	$ 19.27	$ 19.27	$ 19.27	$ 19.27	$ 19.27	$ 19.27
Taxes	$ 6.88	$ 8.57	$ 10.60	$ 12.97	$ 15.90	$ 19.28	$ 23.33
Oil Royalties	$ 8.84	$ 9.39	$ 10.05	$ 10.82	$ 11.73	$ 12.79	$ 14.02
Net Earnings	$ -	$ 2.89	$ 6.35	$ 10.39	$ 15.12	$ 20.54	$ 26.78
Maintenance	$ 8.45	$ 8.45	$ 8.45	$ 8.45	$ 8.45	$ 8.45	$ 8.45
Other	$ 15.89	$ 15.92	$ 15.97	$ 16.02	$ 16.07	$ 16.14	$ 16.22
Supply Cost	**$ 86.53**	**$ 91.70**	**$ 97.88**	**$ 105.12**	**$ 113.75**	**$ 123.67**	**$ 135.28**
Other Revenue	$ 3.31	$ 3.31	$ 3.31	$ 3.31	$ 3.31	$ 3.31	$ 3.31
Oil Supply Price	**$ 83.22**	**$ 88.39**	**$ 94.57**	**$ 101.81**	**$ 110.44**	**$ 120.36**	**$ 131.97**

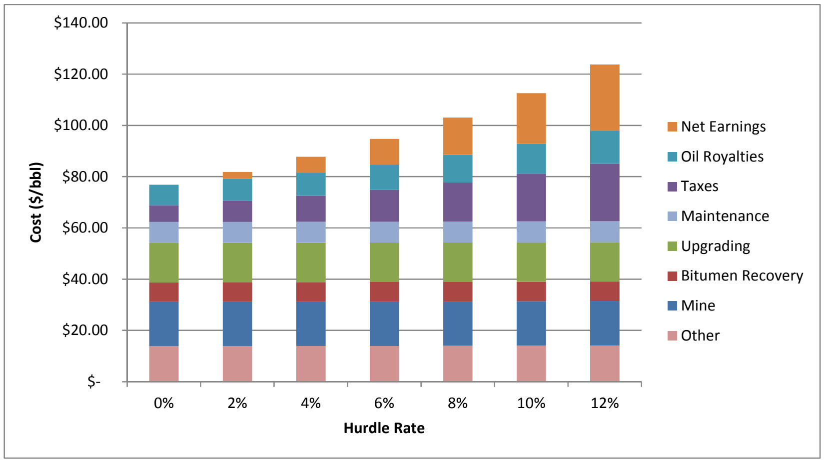

Figure 8.9: Supply cost for air-fired ex situ oil sands production scenario as a function of hurdle rate.

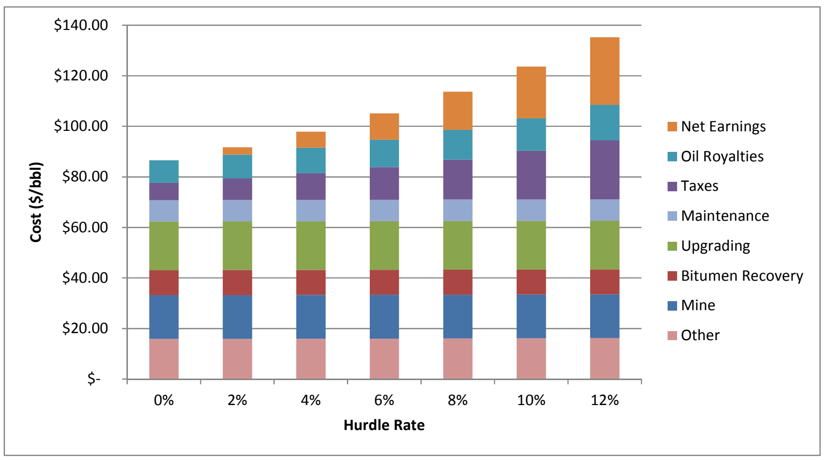

Figure 8.10: Supply cost for oxy-fired ex situ oil sands production scenario as a function of hurdle rate.

The supply price to produce refinery-ready SCO is $75.50–$122.42/bbl for the air-fired case and $83.22–$131.97/bbl for the oxy-fired case. These supply prices include (1) all costs (capital and operating expenses, taxes, royalties, net earnings computed from the hurdle rate) to produce SCO and transport it to market and (2) all non-oil revenue streams. The supply cost at a hurdle rate of 0% is the cost of the project without any investor profit.

For the air-fired case at a 0% hurdle rate, the highest costs are for mining ($17.31/bbl), upgrading ($15.38/bbl), and bitumen recovery ($7.62/bbl). At a 12% hurdle rate, the highest cost categories are net earnings ($25.77/bbl), taxes ($22.42/bbl), and mining ($17.31/bbl). Taxes are tied to net earnings, which rise with increasing hurdle rate; see Section 8.3.2.2. When switching from an air-fired to an oxy-fired system, both the bitumen recovery and upgrading cost categories (0% hurdle rate) rise. Hence, for an oxy-fired system at a 0% hurdle rate, upgrading ($19.27/bbl) replaces mining as the highest cost category and the cost of bitumen recovery rises to $9.89/bbl. At a 12% hurdle rate, the highest cost categories for oxy-firing are net earnings ($26.78), taxes ($23.33/bbl), and upgrading ($19.27/bbl).

Upgrading includes delayed coking, hydrotreating, the hydrogen plant, sour water stripper, amine treatment unit, sulfur recovery unit, and CO_2 compressor (if applicable).

The capture of CO_2 increases costs by \$9.63–\$11.46/bbl depending on the hurdle rate while the sale of CO_2 nets only \$1.90/bbl (see Table 8-13). Taxing CO_2 at the rate of \$25 per ton increases the base case supply price for air-firing by \$2.26 to \$75.50/bbl at a 0% hurdle rate, which is still less than the \$83.22/bbl supply price for oxy-firing (0% hurdle rate). CO_2 would have to be taxed at approximately \$85 per ton for the supply price of the air- and oxy-fired systems to be equal.

8.3.2.2 Supply Costs that Vary with Hurdle Rate

Figure 8.11 shows the supply costs that are a function of hurdle rate as they are tied to the price of oil. All other costs listed in Tables 8-11 and 8-12 (and below in Tables 8-13 and 8-14) are fixed with respect to hurdle rate.

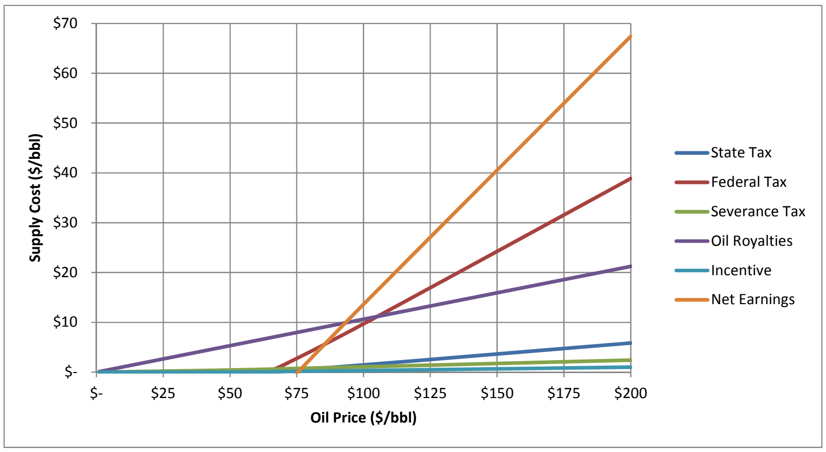

Figure 8.11: Supply cost (\$/bbl) of cost components that are dependent on oil price.

"Incentive" refers to incentive compensation.

State and federal corporate income taxes and incentive compensation are zero until the oil price reaches about \$65/bbl, at which price cash flow during production years becomes positive. The net earnings, however, stay negative until oil sells for at least \$76/bbl for the air-fired base case and \$83/bbl for the oxy-fired base case as shown in Tables 8-11 and 8-12.

Net earnings are not positive until NPV = 0.

8.3.2.3 Detailed Supply Price Breakdowns

Detailed supply price breakdowns for both air- and oxy-firing at a 0% hurdle rate are given in Tables 8-13 and 8-14. Due to rounding error, the "Total" column may differ from the sum across any given row by \$0.01. Also, fuel cost in these tables refers only to natural gas and does not include diesel fuel and other types of fuels that might be necessary to operate mining equipment, vehicles, etc.

The operating cost model for the mine [13] does not provide separate cost categories for anything in the table but capital and labor. The "Other" category includes all operating costs except for labor: "supplies and materials, equipment operation, administration, and sundry items."

Table 8-13. Detailed supply price breakdown for air-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Surface Mine	$ 1.26	$ 5.99	$ -	$ -	$ -	$ -	$ -	$ 10.07	$ 17.31
	Bitumen Recovery	$ 1.86	$ 1.94	$ 0.08	$ 1.99	$ 0.08	$ 0.28	$ -	$ 1.40	$ 7.62
Upgrading	Delayed Coker	$ 1.14	$ 1.70	$ 0.23	$ 0.55	$ 0.00	$ 0.29	$ -	$ -	$ 3.89
	Hydrotreater	$ 2.25	$ 2.19	$ 0.44	$ 1.11	$ 0.00	$ -	$ -	$ 0.08	$ 6.07
	H_2 Plant	$ 0.23	$ 0.73	$ 0.01	$ 2.21	$ 0.01	$ -	$ -	$ -	$ 3.19
	Sour Water Stripper	$ 0.12	$ 0.49	$ 0.01	$ -	$ -	$ 0.09	$ -	$ -	$ 0.70
	Amine Treatment Unit	$ 0.01	$ 0.49	$ 0.00	$ -	$ -	$ 0.28	$ -	$ -	$ 0.78
	Sulfur Recovery Unit	$ 0.01	$ 0.49	$ 0.00	$ -	$ -	$ 0.28	$ -	$ -	$ 0.78
Delivery	Oil Pipeline	$ 0.80	$ -	$ 0.21	$ -	$ -	$ -	$ -	$ -	$ 1.01
Other	Water Pipeline	$ 0.07	$ -	$ 0.06	$ -	$ -	$ -	$ -	$ -	$ 0.14
	CO_2 Compressor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 0.30
		R-134a	Water Reservoir	$ 0.08
		Solvent	Site Preparation	$ 0.56
		Operating Cost Model for Mine	Service Facilities	$ 0.56
			Contigency	$ 1.39
	** Taxes includes:	State Tax	Permitting	$ 0.12
		Federal Tax	Maintenance	$ 8.17
		Severance Tax	Overhead	$ 2.76
		Property Tax	Research	$ 0.74
			Administration	$ 1.51
			Incentive Compensation	$ 0.16
			Insurance	$ 0.98
			Taxes**	$ 6.58
			Royalties - Oil	$ 8.02
			Royalties - IP	$ 2.23
			Working Capital	$ -
			Land	$ 0.21
			Startup	$ 1.06
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 76.90**
			CO_2	$ -
			Export Steam	$ 0.27
			Petroleum Coke	$ 1.10
			Sulfur	$ 0.04
		Non-Oil Revenue Subtotal		**$ 1.41**
Oil Supply Price				**$ 75.50**

Table 8-14. Detailed supply price breakdown for oxy-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Surface Mine	$ 1.26	$ 5.99	$ -	$ -	$ -	$ -	$ -	$ 10.07	$ 17.31
	Bitumen Recovery	$ 1.86	$ 1.94	$ 0.08	$ 1.95	$ 0.08	$ 0.28	$ 2.31	$ 1.40	$ 9.89
Upgrading	Delayed Coker	$ 1.14	$ 1.70	$ 0.23	$ 0.54	$ 0.00	$ 0.29	$ 0.84	$ -	$ 4.73
	Hydrotreater	$ 2.25	$ 2.18	$ 0.44	$ 1.09	$ 0.00	$ -	$ 1.79	$ 0.08	$ 7.83
	H_2 Plant	$ 0.23	$ 0.73	$ 0.01	$ 2.16	$ 0.01	$ -	$ 1.34	$ -	$ 4.48
	Sour Water Stripper	$ 0.12	$ 0.49	$ 0.01	$ -	$ -	$ 0.09	$ -	$ -	$ 0.70
	Amine Treatment Unit	$ 0.01	$ 0.49	$ 0.00	$ -	$ -	$ 0.28	$ -	$ -	$ 0.77
	Sulfur Recovery Unit	$ 0.01	$ 0.49	$ 0.00	$ -	$ -	$ 0.28	$ -	$ -	$ 0.77
Delivery	Oil Pipeline	$ 0.80	$ -	$ 0.21	$ -	$ -	$ -	$ -	$ -	$ 1.01
Other	Water Pipeline	$ 0.07	$ -	$ 0.06	$ -	$ -	$ -	$ -	$ -	$ 0.14
	CO_2 Compressor	$ 0.21	$ 0.49	$ 0.44	$ -	$ 0.04	$ -	$ -	$ 0.21	$ 1.39

Notes				
Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 0.33
		R-134a	Water Reservoir	$ 0.08
		Solvent	Site Preparation	$ 0.58
		Operating Cost Model for Mine	Service Facilities	$ 0.58
			Contigency	$ 1.43
	** Taxes includes:	State Tax	Permitting	$ 0.12
		Federal Tax	Maintenance	$ 8.45
		Severance Tax	Overhead	$ 2.90
		Property Tax	Research	$ 0.74
			Administration	$ 1.57
			Incentive Compensation	$ 0.17
			Insurance	$ 1.01
			Taxes**	$ 6.88
			Royalties - Oil	$ 8.84
			Royalties - IP	$ 2.52
			Working Capital	$ -
			Land	$ 0.22
			Startup	$ 1.10
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 86.53**
			CO_2	$ 1.90
			Export Steam	$ 0.27
			Petroleum Coke	$ 1.10
			Sulfur	$ 0.04
		Non-Oil Revenue Subtotal		**$ 3.31**

The increased cost for oxy-firing is mostly due to the cost of O_2 ($6.28/bbl) with small increases also noted for the electricity and labor needed for the CO_2 compression system. Additionally, the higher capital cost of the oxy-firing system propagates through cost categories that are defined as fractions of capital cost (site preparation, service facilities, contingency, etc.), resulting in increases on the order of cents. These cost increases are partially offset by the sale of CO_2.

Total water costs can be determined by adding up the "Water" column entries, the "Water Pipeline" row entries, and the "Water Reservoir" entry.

The costs of purchasing, delivering, and treating water are minimal ($0.31/bbl and $0.35/bbl for air- and oxy-firing, respectively). Even if the cost of water were to increase by an order of magnitude to $500 per acre-foot per year (base case cost is $50 per acre-foot per year), water costs would only increase by $0.16/bbl to $0.46/bbl and $0.52/bbl for air- and oxy-firing, respectively.

8.3.3 Supply Price Evaluation for Production of Bitumen

The supply prices given in the previous section are for producing SCO delivered to refining markets in Salt Lake City. In this section, supply prices for producing bitumen at the plant gate are determined by zeroing out the costs associated with upgrading and delivery in the Supply Price Method as described in Section 6.3.3. The supply costs by category are listed in Table 8-15 as a function of hurdle rate. The supply price is the same as the supply cost as there are no non-oil revenue streams.

Excluded costs are those for the delayed coker, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, sulfur recovery unit, CO_2 compressor (if applicable), and oil pipeline. Included costs are those for the mine, water pipeline, reservoir, and all cost categories that are functions of other costs (service facilities, site preparation, land purchase, utility plants, etc.).

Table 8-15. Plant gate bitumen supply costs/price as a function of hurdle rate for ex situ oil sands production.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Mine	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31	$ 17.31
Bitumen Recovery	$ 7.72	$ 7.72	$ 7.72	$ 7.72	$ 7.72	$ 7.72	$ 7.72
Upgrading	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxes	$ 2.81	$ 3.18	$ 3.74	$ 4.58	$ 5.67	$ 6.97	$ 8.48
Oil Royalties	$ 4.41	$ 4.56	$ 4.76	$ 5.02	$ 5.36	$ 5.75	$ 6.21
Net Earnings	$ -	$ 0.84	$ 1.96	$ 3.36	$ 5.05	$ 7.05	$ 9.38
Maintenance	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75	$ 2.75
Other	$ 11.56	$ 11.56	$ 11.58	$ 11.59	$ 11.61	$ 11.64	$ 11.67
Supply Cost	**$ 46.56**	**$ 47.93**	**$ 49.81**	**$ 52.34**	**$ 55.48**	**$ 59.19**	**$ 63.52**
Other Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oil Supply Price	**$ 46.56**	**$ 47.93**	**$ 49.81**	**$ 52.34**	**$ 55.48**	**$ 59.19**	**$ 63.52**

Comparing supply costs in Table 8-11 with those in this table, the cost of upgrading, transportation to market, and treatment of waste streams is $30.34/bbl, which is the difference in supply cost at a 0% hurdle rate. This supply cost difference increases with hurdle rate due to the impact of cost categories that are linear functions of hurdle rate such as taxes, royalties, and net earnings.

While it might seem financially attractive to sell bitumen rather than SCO based on these numbers, one should keep in mind that over the long term, the price differential between WTI and raw bitumen at the "plant gate, " currently approximately $30 [37], should reflect the marginal cost of upgrading and transportation to market. Also, a bitumen market where the price would reflect this $30 differential is only reachable from the Uinta Basin at great cost, a cost that is not included in Table 8-15. Therefore, the values in Table 8-15 are only meant to illustrate the range of supply prices that can be obtained depending on what costs are included in the calculation and what the assumed product is. When comparing supply prices in this report with those from other sources, one must consider what the assumed product is, whether and where there is a market.

8.3.4 Net Present Value for Various Price Forecasts

The profitability of the air-fired base case is measured using the NPV Method with three EIA energy price forecasts: low, reference, and high [27]. The NPV is computed using the hurdle rate to discount the cash flows. For the air-fired base case, Table 8-16 lists the NPV computed using the three EIA price fore-

See Section 5.2.3 for details about the NPV Method.

casts for hurdle rates ranging from 0–21.7%. For the EIA reference forecast, the IRR is 13.9% while for the EIA high forecast, it is 21.7%. There is no IRR for the EIA low forecast as the NPV is negative at the 0% hurdle rate.

The IRR is the hurdle rate for which NPV = 0.

Table 8-16. NPV of air-fired base case scenario (in billions of US$).

Hurdle	EIA Price Forecast		
Rate	Low	Reference	High
0.0%	$ (.53)	$ 2.17	$ 4.32
2.0%	$ (.54)	$ 1.51	$ 3.15
4.0%	$ (.55)	$ 1.03	$ 2.30
6.0%	$ (.55)	$ .69	$ 1.69
8.0%	$ (.55)	$ .43	$ 1.24
10.0%	$ (.55)	$ .24	$ .90
12.0%	$ (.55)	$ .10	$ .64
13.9%	$ (.55)	$ -	$ .45
21.7%	$ (.53)	$ (.24)	$ -

The ex situ oil sands base case scenario is not profitable at any hurdle rate under the low energy price forecast; a negative NPV indicates that profits will be less than the specified hurdle rate. Since higher hurdle rates give larger discounts to cash flows each year, losses shrink as the hurdle rate increases, approaching a low price forecast limit of -$176 million as the hurdle rate goes to infinity.

Under the reference energy price forecast, the NPV is positive for all values of hurdle rate less than or equal to the IRR, which is 13.9%. Under the high energy price forecast, the IRR is 21.7% with the operation profitable for all values of hurdle rate analyzed. These values of IRR are the highest computed of the four scenarios analyzed in this report, meaning that ex situ oil sands development will produce the highest rates of return to investors given this report's assumptions.

8.3.5 Supply Price Sensitivity

Using the Supply Price Method, the sensitivity of the supply price of oil to the following parameters is investigated: bitumen saturation, bitumen and solvent recovery efficiency, H_2 consumption during upgrading, maintenance costs, fuel expenses (e.g. natural gas), and tax and royalty rates applied to the operation. For most of these parameters, high and low values relative to the base case are assumed and the resulting supply price is computed. Only low values relative to the base case are assumed for federal and state corporate income tax.

Bitumen saturation is a measure of the bitumen content of the oil sands resource.

The bitumen saturation and recovery efficiency ranges that are evaluated affect the mining model, which is constrained by the maximum ore mining rate of 15,384 TPD, and the resultant production capacity. Table 8-17 gives the various values of the bitumen saturation and recovery efficiency that are investigated in the sensitivity analysis with the corresponding maximum SR, production capacity, and ore mining rate. The base case scenario represents an optimistic production level given publicly available documents about the resource. The low bitumen saturation and/or low recovery efficiency combinations represent what might happen to costs if the mine were not as productive as anticipated, leaving all equipment (bitumen recovery unit, coker, hydrotreater, etc), not just the mine, running at less than full production capacity.

A 2008 report on North American oil sands states that based on the Canadian experience, commercial success in mining oil sands is dependent on an SR of 1:1 [38] while this report assumes that mining continues until an SR of 4:1 is reached.

Table 8-17. Oil sands mining model output for a range of bitumen saturation and recovery efficiency values.

See Section 8.1.1 for a mining model description.

Scenario	Max SR	Production Capacity	Ore Mining Rate (TPD)
Base (10 wt% bitumen, 95% recovery)	4.00	100%	15,384
Low (5 wt% bitumen)	4.00	41.2%	15,384
Wells et al. (8 wt% bitumen)	4.00	69.4%	15,384
High (15 wt% bitumen)	2.52	100%	9,686
Low recovery (90%)	4.00	85.3%	15,384
High recovery (100%)	3.80	100%	14,614
All unfavorable (5 wt% bitumen, 90% recovery)	4.00	39%	15,384
All favorable (15 wt% bitumen, 100% recovery)	2.39	100%	9,202

Table 8-18 lists the supply price as a function of hurdle rate over the ranges of parameters tested. The bitumen saturation of the mined oil sands has the largest impact on the supply price. Bitumen saturation determines the volume of material (both the resource and the overburden) that must be mined and processed, impacting the capital and operating costs of both the mining and bitumen recovery unit operations.

Assuming the average EIA reference price forecast of $131.85/bbl (see Table 5-3), an operation processing oil sands with 15% bitumen saturation is profitable (e.g. positive NPV) for all values of hurdle rate analyzed (up to 12%). However, if the oil sands are of low quality (5% bitumen saturation), the operation is only profitable for hurdle rates < 2.4%. Under EIA's high oil price forecast (average price of $192.45), an operation processing low quality oil sands is profitable up to a hurdle rate of 9.0%. In the supply cost analysis conducted by Wells et al. [36] and summarized by Oblad et al. [10], it is noted that increasing the grade of oil sands from 8 wt% to 10 wt% reduces the supply price by $8/bbl. Here, increasing the bitumen saturation from 8 wt% to 10 wt% reduces the supply price by $16/bbl at a 4% hurdle rate and by $26/bbl at a 12% hurdle rate. Because Wells et al. [36] did not use the same Supply Price Method approach, the differences in per barrel costs cannot be analyzed directly. However, the authors conclusions are still timely [10]: "... small plants operating on a particularly rich and accessible grade of tar sand may be highly profitable, whereas larger plants with reduced average grade may be less profitable. Owing to the module sizes of the mining, recovery, and upgrading equipment, it does not appear that there is a major economy of scale above about 20,000 barrels/day."

The cost impacts of the other parameters tested were similar in magnitude. High efficiency bitumen and solvent recovery may be critical to meeting environmental requirements for disposal of oil sands tailings, but the impact on the per barrel cost is not large. With 5% solvent loss (95% recovery efficiency), the makeup solvent feed rate is 1.08 gpm at a cost of $8.98 per

Table 8-18. Sensitivity of supply price for ex situ oil sands scenario to various parameters.

Ex Situ Oil Sand (Air-Fired)		Supply Price of Oil ($/bbl)			
		Hurdle Rate			
Variable	**Range**	**0%**	**4%**	**8%**	**12%**
Base Case	**---**	**$ 75.50**	**$ 86.37**	**$ 101.65**	**$ 122.42**
Bitumen Saturation (wt%)	**10%**				
Low	5%	$ 129.52	$ 153.88	$ 188.82	$ 234.20
Wells et al., 1984 [a]	8%	$ 88.46	$ 102.30	$ 121.99	$ 148.34
High	15%	$ 62.72	$ 73.58	$ 88.24	$ 107.80
Bitumen and Solvent Recovery	**95%**				
Low	90%	$ 79.90	$ 91.36	$ 107.53	$ 129.51
High	100%	$ 71.76	$ 82.55	$ 97.62	$ 118.04
Upgrading H_2 Consumption (SCF/bbl)	**412**				
Low	206	$ 73.34	$ 84.08	$ 99.18	$ 119.71
High	618	$ 77.58	$ 88.58	$ 104.00	$ 124.96
Maintenance (% of C_{TDC})	**5%**				
Low	2%	$ 68.89	$ 79.59	$ 94.70	$ 115.47
High	8%	$ 82.10	$ 93.16	$ 108.59	$ 129.37
Fuel Costs	**100%**				
Low	50%	$ 72.06	$ 82.91	$ 98.14	$ 118.87
High	150%	$ 78.93	$ 89.84	$ 105.15	$ 125.97
Royalties (% of Sales) [b]	**8.0%-12.5%**				
Federal Land - standard fixed rate [c]	12.5%	$ 77.14	$ 88.69	$ 104.79	$ 126.67
Federal Land - oil shale rate [d]	5.0%-12.5%	$ 75.49	$ 86.25	$ 101.44	$ 122.09
Low [e]	5.0%	$ 71.26	$ 81.85	$ 96.59	$ 116.60
Federal Taxes (% of Taxable Income) [f]	**35%**				
Low [g]	15%	$ 73.18	$ 81.80	$ 93.84	$ 109.85
State Taxes (% of Taxable Income) [h]	**5%**				
SB65 Tax Credit [i]	< 2%	$ 75.05	$ 85.65	$ 100.50	$ 120.60
Combined	---				
All Unfavorable [j]	---	$ 164.26	$ 192.47	$ 233.06	$ 285.75
All Favorable [k]	---	$ 44.54	$ 52.51	$ 63.37	$ 77.42

[a] *Wells et al. [36], as summarized in Oblad et al. [10], use a bitumen saturation of 8 wt% in their economic analysis of SCO production from Utah oil sands.*
[b] *Royalty rate for oil shale/oil sands leases on state (SITLA) lands; see Section 3.4.1.1*
[c] *Standard fixed rate for conventional oil lease*
[d] *Royalty rate given in 2008 royalty rules; see Section 3.4.1.1*
[e] *Lowest royalty rate proposed on either federal or state lands*
[f] *Federal corporate income tax rate based on taxable income*

[g] *Lowest federal corporate income tax rate*
[h] *Standard state corporate income tax*
[i] *State corporate income tax rate after state tax credit is applied; see Section 3.4.4*
[j] *All unfavorable = Low bitumen saturation, low bitumen/solvent recovery, high* H_2 *requirement, high maintenance costs, high fuel costs, 12.5% royalty rate*
[k] *All favorable = High bitumen saturation, high bitumen/solvent recovery, low* H_2 *requirement, low maintenance costs, low fuel costs, 5% royalty rate, federal income tax of 15%, state tax credit applies*

gallon or $1.40/bbl of oil. Reducing the solvent recovery efficiency to 90% doubles the required makeup solvent feed rate (2.22 gpm) and cost ($2.88/bbl). Overall, varying the bitumen and solvent efficiency by ± 5% changes the supply price by ± $4–$7 depending on the hurdle rate. For reference, US Oil Sands claims a solvent recovery efficiency of 98+% and bitumen recovery efficiencies up to 97.5% with their Ophus Process [39].

Since early work with Utah bitumens focused on direct hydrotreating of the bitumens without a primary upgrading step [20], estimates for H_2 consumption of bitumen-derived fuels from Asphalt Ridge oil sands were made by utilizing compositional information from various sources [12,20] and performing elemental mass balances as described in Section 8.1.6. To test the sensitivity of the supply price to the base case estimate for H_2 consumption, the base case value of 412 SCF/bbl (12.5 cubic meters/bbl) is varied by ± 50% in the sensitivity analysis. These variations shift the supply price by ± $2–$3/bbl.

Maintenance costs are estimated as a percentage of C_{TDC}, with recommended values ranging from 2% [25] to 11.5% [13]. Since C_{TDC} is $588 million (air-fired case), annual maintenance costs are on the order of tens of millions of dollars and the choice of maintenance percentage has a significant impact on the supply price. Increasing or decreasing the base case value of 5% by three percentage points results in a ± $6–$7/bbl change in the supply price of oil.

Fuel (e.g. natural gas) is the only significant "utilities" contributor to the supply price. Altering the fuel costs ± 50% moves the supply price by ± $3–$4/bbl, reflecting the impact of changes in fuel purchase price or fuel utilization. It should be noted that overall natural gas consumption reflected in the base case value has been reduced by accounting for the heating value of the waste fuel gases from the fractionator column in the delayed coker unit, which supply 32% of the total required heating.

Fuel costs exceed the combined cost of steam and electricity by a factor of three and the cost of water by nearly a factor of 40.

Table 8-18 also shows the supply price for oil assuming a range of royalty and tax rates/credits that federal and state governments have suggested for oil sands and/or conventional oil development. The impact of tax and royalty policies increases with hurdle rate. Because of the high federal income tax rate, changes to federal tax policy have a larger impact on supply price than the recent change to Utah state tax policy. Reducing the federal corporate income tax rate from 35% to 15% reduces the supply price of oil by $12.57 (hurdle rate of 12%) while applying the state tax credit reduces the supply price by $1.82. Also at a 12% hurdle rate, a fixed royalty rate of 5% reduces the supply price of oil by $5.82 over the base case while a fixed royalty rate of 12.5% raises the supply price by $4.25.

In its 2012 session, the Utah Legislature based a bill that established a tax credit for alternative energy development; see Section 5.4.3.

Lastly, the combined effect on the supply price of applying all the favorable and unfavorable parameters in Table 8-18 is given as a function of hurdle rate. Given the parameter range that is examined, these "All Favorable" and "All Unfavorable" prices provide outer bounds on the supply price range for this scenario.

8.3.6 Analysis and Summary

This section examines the supply costs and prices for this scenario in the context of published information about commercial-scale oil sands development in Canada. The discussion builds on the question of economic viability for U.S. oil sands development that is implicitly addressed in the sensitivity analysis in the previous section. Based on the sensitivity analysis, this ex situ oil sands extraction scenario is financially attractive only if the quality of the resource is high. That is, the deposit is of sufficient thickness and lateral extent to supply the bitumen separation process with 15,000 TPD (14,000 MTPD) of oil sands in the range of 8–10 wt% bitumen saturation.

Projected supply costs for Canadian oil sands operations were published in a 2012 CERI report [37] for a project timeline extending from 2011–2045. CERI uses a methodology that is essentially the same as the Supply Price Method in this report: they fix a hurdle rate (10%) and compute the constant price needed to attain a project ROR/IRR equal to that rate. The report gives both supply costs at the plant gate (transportation and blending costs are excluded) and "WTI-equivalent" supply costs (adjusting for blending and transportation costs for SCO or blended bitumen). In their model, the authors of the CERI report assume that an integrated mining/extraction/upgrading operation has a production capacity of 115,000 BPD, production life is 30 years, the product is SCO, and the plant operates at 89% capacity. The "WTI-equivalent" supply cost is \$95.47. In this report (10,000 BPD operation), the "WTI-equivalent" supply cost for the base case at a 10% hurdle rate is \$112.61, which is 18% greater than the CERI supply cost.

All numbers from the CERI report (2010 C\$) have been adjusted to 2012 US\$ using the CEPCI inflation index and assuming a 1:1 C\$/US\$ exchange rate.

The hurdle rate is the minimum expected rate of return a project needs to attain in order to be considered profitable. The ROR may be more or less than the hurdle rate because it depends on the actual path of prices and costs. If an investor had a crystal ball and knew in advance that the ROR of a project would turn out less than the hurdle rate, s/he would not invest in the project.

A supply cost breakdown comparing the CERI report with this report's air-fired base case scenario is shown in Table 8-19. Not all costs in the two reports have been aggregated in the same way and the project scales and timelines differ, some interesting comparisons can still be made. First, the government take (taxes + royalties) in the CERI report (e.g. Canada) is \$19.69 while in this Utah-based scenario, it is \$30.32, a difference of more than 30%. Second, while the heating requirements in this report are double those reported in CERI for an integrated mining/upgrading operation, the fuel (e.g. natural gas) cost is higher by a factor of only 1.6. Both reports use EIA prices for natural gas costs, but this report assumes a constant fixed price for natural gas (real 2012 US\$) based on EIA price projections to 2035 (\$6.16/MMBtu) while CERI extends the projection period to 2044 by inflating natural gas prices by 2.5% annually after 2035. Also, the fraction of total required heating that is attributed to waste gases and subtracted from the purchase requirement is 32% in this report. CERI notes a "Non-Royalty Applicable" natural gas usage. If this is the equivalent of a fuel credit, then the credit is 25%. Third, given the much larger scale of operations analyzed with the CERI model, the expected trend would be for unit capital costs to be lower for the larger projects due to economies of scale. Nevertheless, capital costs (including ROR or net earnings of 10%) show the opposite trend, with costs of 39.83/bbl in this report and \$38.10/bbl in the CERI report. A detailed analysis of

Both values are based on a 10% hurdle rate.

The total energy requirement in this study is 1.47 gigajoules per barrel (GJ/bbl) while that for the CERI study is 0.72 GJ/bbl. However, because the heating value of gases from the delayed coker is recovered in this study, only 0.96 GJ/bbl of fuel must be purchased.

Table 8-19. "WTI-equivalent" supply cost breakdown for an integrated mining and upgrading operation (10% hurdle rate); data from Millington et. al. [37] and from the Supply Price Method analysis in this report (see Tables 8-11 and 8-13).

Cost category	CERI 115,000 BPD ($/bbl)	Supply Price Method Air-fired, 10,000 BPD ($/bbl)
Emissions compliance costs[a]	$0.68	$0.12
Income taxes[b]	$7.12	$18.51
Royalties	$12.80	$11.81
Abandonment costs	$0.06	–
Other operating costs (fixed, variable, electricity)[c]	$20.64	$36.28
Fuel (natural gas)	$3.68	$5.85
Blending & transportation[d]	$1.52	$1.01
Operating working capital[e]	$0.96	–
Fixed capital (initial, sustaining, & ROR)[f]	$48.01	$39.03
Total supply cost	$95.47	$112.61

[a] *Permitting*
[b] *State and federal income taxes, property taxes, and severance taxes*
[c] *All costs not explicitly included in other categories except transportation (catalysts, research, administration, incentive compensation, mining, solvent, refrigerant, steam, water, labor, overhead, insurance, and intellectual property royalties)*
[d] *Only transportation costs are included in the Supply Price Method column*
[e] *Working capital is counted as a cost at the beginning of the project and income at the end, so it has no cost unless costs are presented in terms of present value*
[f] *All capital costs included in C_{TDC}, land, startup, and maintenance; also includes ROR or "net earnings"*

the cost categories driving these capital cost differences is not possible with the available information.

While this supply price breakdown provides additional information about where the numbers reported here and in CERI differ, there is insufficient information to fully understand what is driving these differences. This comparison reveals the uncertainty inherent in these types of analyses and the difficulty in comparing costs across methodologies.

An EROI for the base case ex situ oil sands production scenario has been estimated by dividing the energy outputs (SCO and coke) by the energy inputs. The inputs include (1) the electricity and natural gas use for each of the processes described in this section, and (2) the energy required for the mining and transport of the sands, steam generation, water delivery, and O_2 production (for the oxy-fired case). Not included in the inputs is the energy required for facilities construction, water treatment, and refrigeration. The

The fuel higher heating value is used as the basis for all energy inputs and outputs.

EROI for the air-fired base case scenario is 4.88 and for the oxy-fired base case scenario is 4.85. Additional details about these EROI numbers are found in Kelly et al. [40].

Because there is no commercial-scale development of Utah oil sands, the uncertainties associated with the cost of development are high. This analysis provides an overview of the factors that impact profitability and clearly states the assumptions that have been made so that the results can be placed in proper context with the other cost estimates that are publicly available.

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9 In Situ Oil Sands Production Scenario

9 In Situ Oil Sands Production Scenario

This section provides a profitability analysis for producing SCO from Utah oil sands using an in situ extraction process at a production capacity of 10,000 BPD. In situ extraction is the method of choice for those oil sands too deep to mine. For this scenario, the SAGD process commonly employed in Canadian in situ oil sands operations is used to extract bitumen from an oil sands deposit located in the P.R. Spring STSA of Utah's Uinta Basin. The size of the P.R. Spring resource is estimated to be 3.3–4.5 billion barrels [1]. Figure 9.1 shows the scenario location within the P.R. Spring STSA. P.R. Spring is located on the southeast flank of the Uinta Basin about 50 miles (80 kilometers) northwest of Grand Junction, Colorado, and about 50 miles south of Vernal, Utah. The P.R. Spring oil sands deposit extends along the length of the eastern Book Cliffs from Willow Creek on the west to the Utah - Colorado border on the east. Oil sands deposits crop out at elevations ranging from 6,500 feet to 8,800 feet (1,981–2,683 meters) on cliff faces in the region. While the land surface is relatively flat, it is incised by steep canyons with intermittent and perennial streams forming dendritic-shaped drainages [1]. Most of the land in the area is public land administered by BLM; see Figure 9.2. A large block of state land, known as the Book Cliffs Planning Unit, plus other scattered sections, are administered by SITLA. Smaller tracts of private lands are also present. The deposit is in a remote area where vehicle access is limited to unimproved and/or oil-well maintenance roads. Roads to the area intersect with I-70 to the south and State Route 45 to the north.

The Book Cliffs Conservation Initiative encompasses 450,000 acres in the P.R. Spring area. Its goal is to improve wildlife habitat in the southeastern Uinta Basin [1].

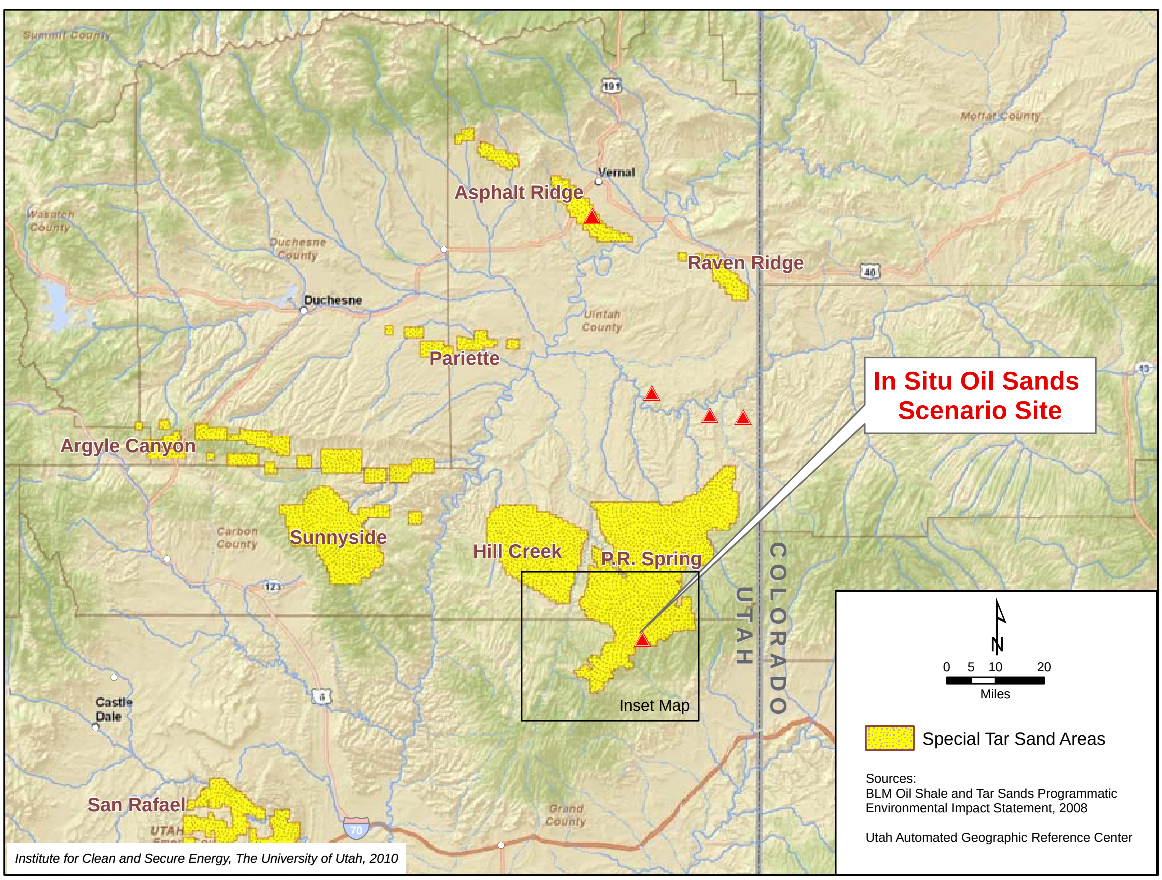


Figure 9.1: Uinta Basin oil sands deposits with location of in situ oil sands scenario identified.

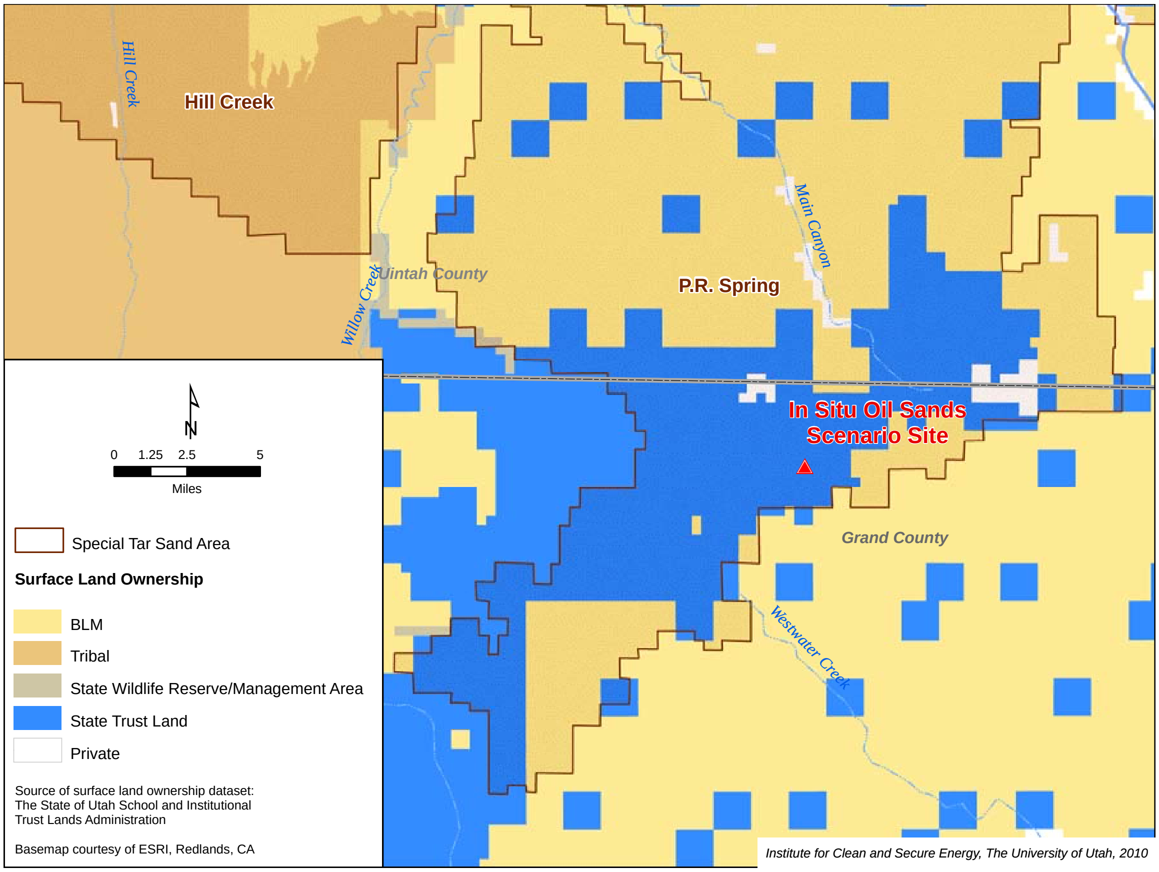


Figure 9.2: Land ownership in the southeast Uinta Basin near the in situ oil sands scenario site.

Gwynn [2] identified five major bitumen-bearing sandstone zones in the P.R. Spring deposit, zones A–E, designated from the deepest to that closest to the surface. In examining the stratigraphy of these five zones across the Uinta Basin, Sinks identified two additional zones below zone A, designated as zones 1 and 2 [3]. Zone E is present in the lower Parachute Creek member above the oil shale Mahogany zone (R-7). Zones A–D are found in the upper Douglas Creek member as shown in Figure 9.3. According to Sinks [3], "The majority of the sands are lacustrine, not fluvial, in origin." Regardless of the depositional environment, the resource is discontinuous and irregular. The total section of oil-impregnated zones, including interburdens, ranges up to 400 feet thick and dips downward to the northwest at 2° to 6°. Zone E is present only in the southwest portion of the deposit, while zones A–D have similar areal extents that cover almost the entire deposit.

Sands that are lacustrine in origin accumulated in a lake environment while fluvial sands were deposited by a river.

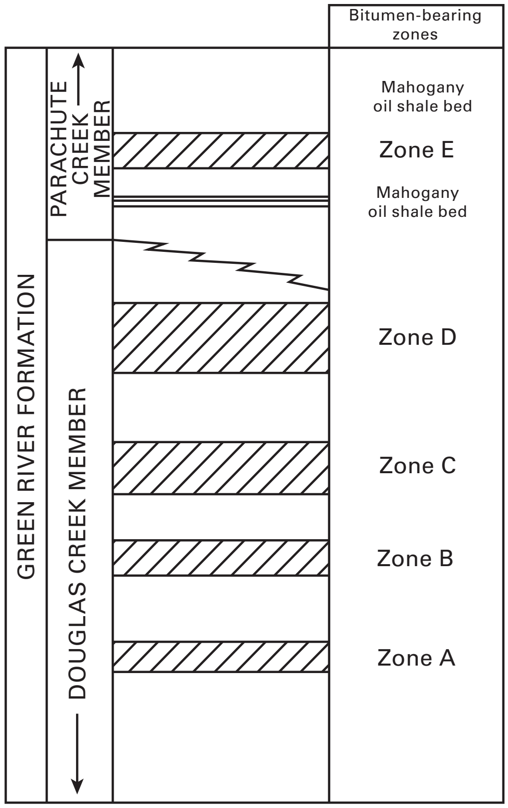


Figure 9.3: Schematic of oil sand zones and detailed core data in the south-eastern Uinta Basin; from Sinks [3].

Economic considerations for the in situ development of oil sands within the P.R. Spring STSA and other Uinta Basin oil sands deposits include the quality (e.g. bitumen content) of the resource, the lateral extent and homogeneity of oil sand zones, the depth to the top of the oil sand zones(s), and the thickness of the oil sand beds within that zone [4]. Critical reservoir properties and the thicknesses of zones A–E in the P.R. Spring STSA are presented in Table 9-1 [3]. Resource assessments by Blackett [1] and Gwynn [4] have both concluded that there are wide variations in the lithology and bitumen content of the deposit (0.5–10.9 wt% in Table 9-1), even over distances as small as a few hundred feet. In Table 9-1, the thickness of the resource varies from 10 feet (3.3 meters) to 64 feet (19.5 meters) with zone B being the thinnest zone. Even though zone D has the greatest thickness, the majority of zone D is between 25–35 feet (7.6–10.7 meters) thick [3]. A more recent analysis by Gwynn [4] corroborates the Table 9-1 data; a histogram of the frequency of thickness of the oil sands beds in P.R. Spring (Figure 9.4a) shows that the majority of the beds are in the 2–35 feet (0.6–10.7 meters) thick range with only a few beds exceeding 60 feet (18.3 meters) in thickness. Figure 9.4b is a histogram of the frequency of the overburden thickness; most beds are within 300 feet (91 meters) of the surface.

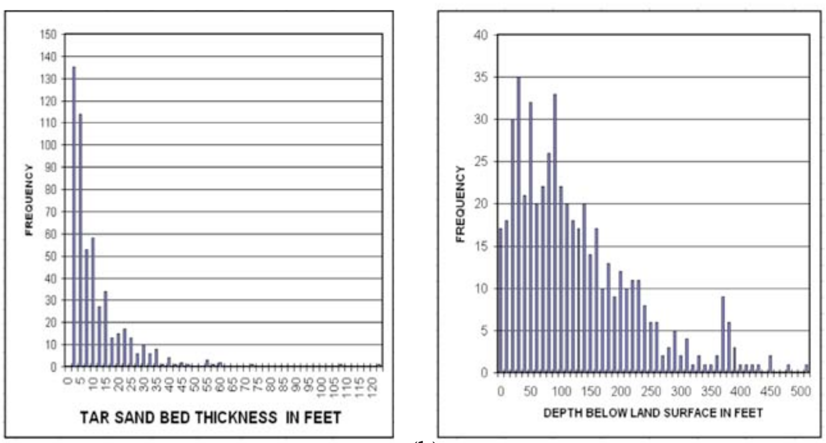
Lithology refers to the description of the physical characteristics of rock layers either from outcrop or from core samples.

Overburden thickness refers to the depth to the top of the oil sand bed.

Table 9-1. Reservoir properties for oil sands zones A–E; from Sinks [3].

Parameter	Zone E	Zone D	Zone C	Zone B	Zone A	Zone 1	Zone 2
Depth to top of zone (feet)[a]	16–102	18–392	24–323	77–451	15–391	113–186	272–363
Thickness (feet)	?–62	14–64	12–53	11–34	10–50	36	123
Porosity (saturated, %)	7.8–19.2	3.2–19.6	1.0–25.7	10.5–28.0	11.9–22.6	n/a	n/a
Permeability (saturated, mD)	9–434	<1–2508	<1–5018	<1–1962	26–1455	n/a	n/a
Bitumen saturation (wt%)	0.9–7.0	1.0–10.9	1.1–7.8	0.5–7.3	1.2–5.6	n/a	n/a

[a] See Appendix C in Sinks [3] for tables listing depth to various zones for a wide range of core samples.



(a) **(b)**

Figure 9.4: Frequency histograms of the (a) oil sand bed thickness and (b) overburden thickness in the P.R. Spring STSA; from Gwynn [4].

What types of deposits are economically recoverable in Alberta via in situ extraction methods? An industry website states that "... in-situ processes require a minimum depth of burial of about 400 m[eters] in order for there to be an adequate seal and hydraulic pressure for the various processes to work" [5]. A 2001 paper by McCormack gives reservoir cutoffs for an economical SAGD project that include a continuous, high quality (> 10 wt% bitumen saturation) pay thickness of at least 39.4 feet (12 meters), a competent caprock, and a reservoir operating pressure of at least 1000 kilopascals (kPa) [6]. However, more recent work suggests that the range for economical SAGD projects may be even wider. Albahlani et al. [7] conclude that "...each reservoir holds its own elements of success and failure and should be treated on [an] individual basis." Also, Palmgren et al. [8] describe a commercial SAGD project whose goal is to "...demonstrate safe in situ production from a shallow bitumen res-

A depth of 400 meters is approximately 1,310 feet.

ervoir...” The base of the caprock for this project is 213 feet (65 meters) and the thickness of the high-quality section of the bitumen deposit (including a low permeability layer) is 164 feet (50 meters).

Despite the wide range of SAGD applicability that has been demonstrated in Alberta, the Utah oil sands resources in general and the P.R. Spring oil sands resource in particular exhibit wide variations in bitumen content and lithology that make in situ production difficult. Figure 9.5, from Gwynn [4], highlights lithological variability. Since the scale of oil production for this scenario (10,000 BPD) would require extensive horizontal drilling that clearly exceeds the length scales over which deposits are continuous, it is not possible to accurately model the SAGD process in the actual geologic setting of the P.R. Spring deposit. Recent work in the Tar Sand Triangle of Utah [9] has identified an area of 84 square miles (218 square kilometers) where the thickness of the oil sands interval exceeds 100 feet (30.5 meters). While the Tar Sand Triangle deposit may be a potential target for in situ development, it is not analyzed in this study because it is outside the Uinta Basin, has difficult access, and is in close proximity to protected public lands.

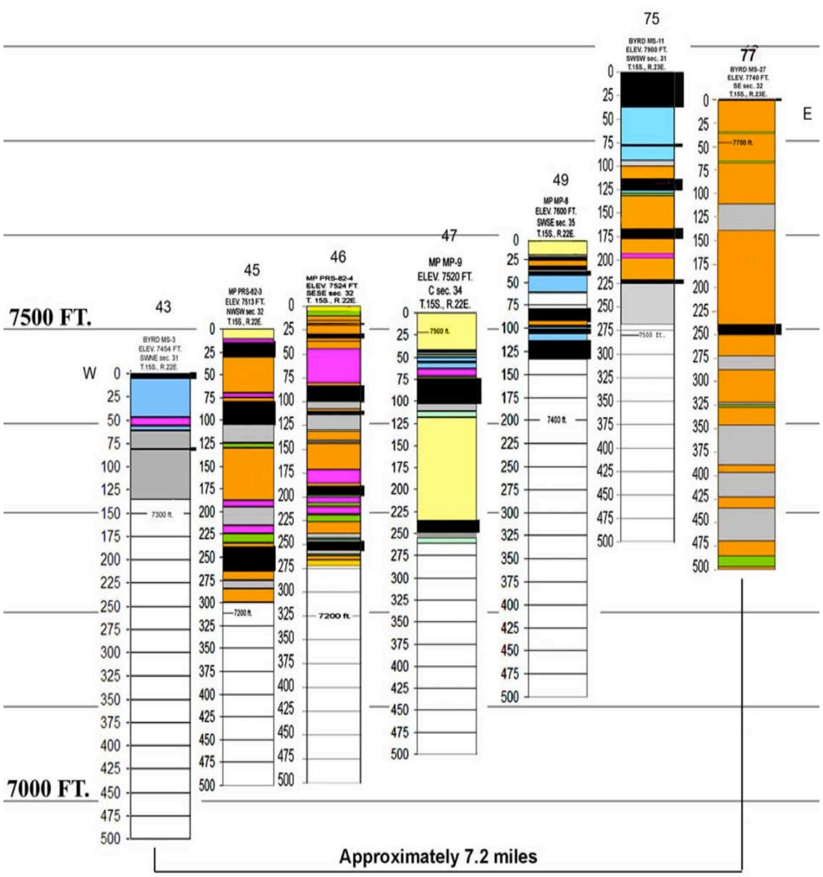


Figure 9.5: Variability of lithology in the P.R. Spring deposit over a distance of 7.2 miles (11.6 kilometers); from Gwynn [4].

Instead, the analysis of the SAGD production costs for this scenario is based on information from a recent SAGD project in Alberta's Athabasca oil sands [10]. Given the relative quality and continuity of the Athabasca resource compared with Utah oil sand resources, this scenario represents a best case “what-if” scenario were a producer to locate an oil sand deposit amenable to in situ development.

9.1 Description of Unit Operations

The overall in situ oil sands production scenario is shown in Figure 9.6 where each block is a unit operation. The production blocks (drilling, SAGD, and the central processing facility or CPF) are based on Connacher's Great Divide SAGD expansion project [10,11]. Everything downstream of production follows the same process as the ex situ oil sands scenario: primary and secondary upgrading, CO_2 compression, and transportation to a refinery. In the following subsections, details of each block are discussed. The individual pieces of major equipment needed are first identified and then capital and operating costs for each unit are summed up to determine the supply costs for the given production rate of SCO. Both air- and oxy-fired heating systems are considered for all operations downstream of production. Processes that are only applicable to oxy-firing are indicated by dashed lines in Figure 9.6. Unless otherwise noted, all unit operations are located at the scenario site in the P.R. Spring STSA.

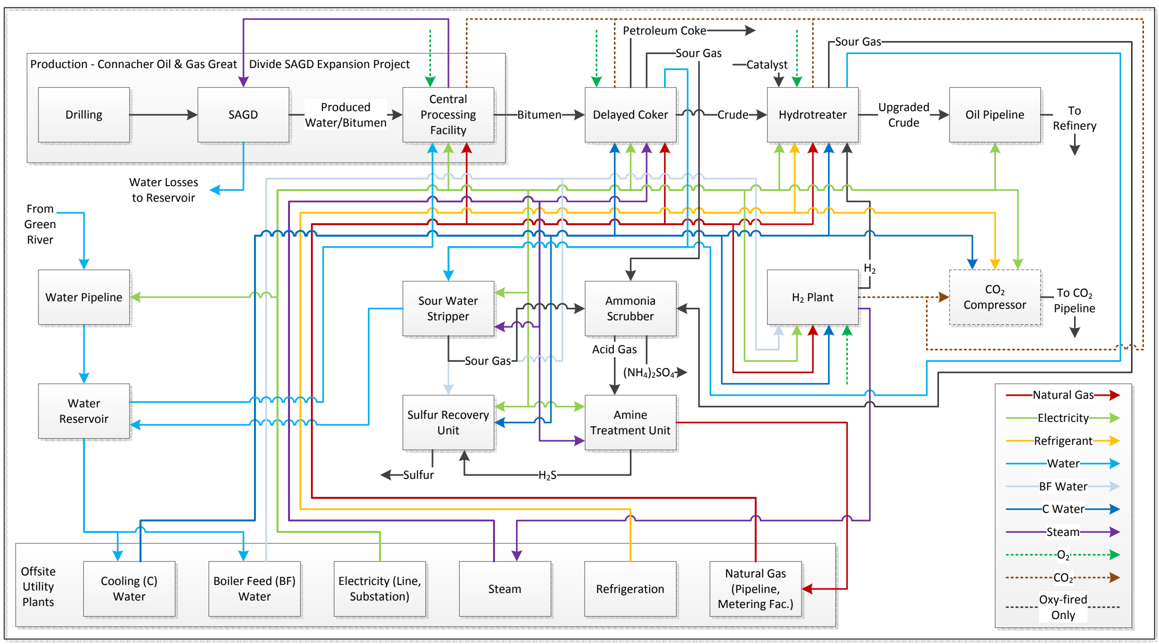


Figure 9.6: In situ oil sands production process overview.

Figure 9.6 and the analysis in this section provide a general overview of the processes involved in the production of SCO from the in situ heating of oil sands and are not an exhaustive list of all unit operations that would be required.

9.1.1 In Situ Production

In this scenario, in situ production of bitumen from oil sands is modeled on the process description for the Great Divide SAGD expansion project, owned by Connacher Oil and Gas Limited [10,11]. Connacher's proposal for the project details the total capital cost, drilling program, bitumen recovery, mass and energy balances, and process equipment necessary to complete a 24,000 BPD expansion of the company's existing Algar SAGD facility in Alberta, Canada. While the geology of Connacher's Athabasca oil sands differs from that of the oil sands in P.R. Spring, any SAGD facility built in the Uinta Basin would have a similar design to the SAGD facility in Alberta. Actual costs would clearly vary, but errors introduced from assuming that costs can be scaled are likely to be much smaller than the errors from assuming that a reasonably continuous band of oil sands can be found in P.R. Spring (or elsewhere in the Uinta Basin) large enough to support a 10,000 BPD operation.

Capital costs and utility requirements are scaled from the Connacher report using the scaling methods described in Section 5. Labor requirements are estimated using Seider's methodology (see Section 9.2.5). A summary of the Connacher data and of the resulting scaled values are shown in Table 9-2, followed by a brief description of the major components of Connacher's SAGD process.

Table 9-2. Capital costs and utility requirements scaled from Connacher [10,11].

Item	24,000 BPD (Connacher)	10,000 BPD (P.R. Spring)	Units	Notes
Total Capital	$629.0 million	$410.9 million	2012 US$	Assumed 1:1 C$ to US$ exchange rate, six-tenths scaling
Capital - Drilling	–	$82.18 million	2012 US$	Assumed 20% of total capital; from Grills [12]
Capital - CPF	–	$328.7 million	2012 US$	Difference of total capital and drilling costs
Well Pairs	217	107		Linear scaling
Make-up Water	0.413 (0.0117)	0.203 (0.0058)	CFS (CMS)	Linear scaling
Fuel (natural gas)	44,855 (15,517,700)	22,063 (7,632,800)	GJ/day (MMBtu/yr)	For both steam & electricity generation, linear scaling

9.1.1.1 Drilling Horizontal Wells

Steam injection and production wells are drilled horizontally into the oil sands deposit. Connacher's original proposal called for 217 well pairs with a true vertical depth average of 1640 feet (500 meters) and an average horizontal length of 2,300 feet (700 meters), for an average total well length of 4,430 feet (1,350 meters). Injector and producer wells are drilled in pairs with injector wells located 16 feet (5 meters) above producer wells.

Scaling linearly, 107 well pairs are required for this scenario. Connacher does not identify what proportion of their expansion's costs are due to drilling. However, according to Grills [12], drilling costs typically account for 20% of the total capital cost of SAGD projects. Using this assumption, drilling is expected to cost $82.2 million, or about $384,000 per well. Drilling follows a scaled version of Connacher's drilling schedule. It occurs over a 16-year period beginning in 2015 as shown in Table 9-3.

These drilling costs are significantly less than the drilling costs assumed for the in situ oil shale production scenario ($384,000 versus $3 million). The average well length for this scenario is approximately 4,430 feet (1350 meters) while for the in situ oil shale scenario, it is approximately 5,800 feet (1,770 meters); see Section 7.1.1.2.

Table 9-3. SAGD drilling schedule; scaled from Connacher [11].

Year	Well Pairs Drilled
1	25
2	1.5
3	3.5
4	7.5
5	1.5
6	4.5
7	7.5
8	17.5
9	2.5
10	11
11	5.5
12	4.5
13	1.5
14	10
15	2
16	1.5
Total	**107**

9.1.1.2 SAGD

Bitumen is recovered in three phases [11]. During the "circulation phase" (60–90 days), well pairs are preheated until there is relatively even heating and communication (flow) between injector and producer wells. Next, steam is injected continuously through the injector in the "SAGD phase," which creates an increasingly large steam chamber around the injector well. Hot fluids (both bitumen and water) collect at the bottom of the chamber and flow into the producer well. The SAGD phase continues until the steam chamber reaches the top of the reservoir (up to 8 years), at which point production rates diminish and further steam injection will lead to heat losses to the overburden. At this point, the "wind down phase" commences. Steam injection is gradually reduced, production stops, and the well is reclaimed.

Produced fluids (water, bitumen, and gas) are lifted to the surface using artificial lift. During the first two years of the SAGD process, this lift comes from injecting natural gas into the production well. Afterwards, submersible pumps are used downhole to produce the necessary lift.

Based on simulations of bitumen recovery for their resource, Connacher estimates that they will recover 54% of the bitumen in place with a cumulative steam to oil ratio (SOR) of 3.7.

9.1.1.3 Central Processing Facility

The CPF separates the produced water, bitumen, and gases from the SAGD process, treats produced water, and generates the steam required for both SAGD and upgrading. The capital and operating costs of the additional steam production required for upgrading (with the exception of the purchase of water, which is included) are not included in this analysis for three reasons: (1) No estimates of the incremental cost of adding steam capacity could be found, (2) the steam requirement for upgrading represents a small fraction of overall steam usage (< 9%), and (3) based on information from Connacher with respect to the range of SORs expected over the project lifetime, their steam generation system appears capable of producing at these slightly increased levels. A brief outline of the process is given below; see the Connacher report [11] for more detail.

The SAGD process uses 5,728 million pounds (2,598 million kilograms) of steam per year. By comparison, the upgrading process requires 590 million pounds (268 million kilograms) of steam and produces 304 million pounds (138 million kilograms) of steam per year.

Produced fluids reach the surface as an emulsion of bitumen, water, and light hydrocarbons in both liquid and gas phases. The two phases are separated at the well pad group separator and are then pumped to the CPF. The fluids are initially cooled at an inlet heat exchanger, recovering some of the heat from the injected steam by preheating boiler feed water. The cooled fluids next enter a free water knockout separator, which is a three-phase separator that removes most of the water and gas from the incoming emulsion.

In the Connacher project, the next step is to add 60º–90º API diluent to the bitumen phase in a gravity separation and filtration vessel. Addition of diluent enables easier separation of bitumen from any water or gas remaining in the bitumen phase and improves the oil quality so that it can be sold as dilbit to a refiner without further processing. However, in this scenario the diluent is not added. Instead, the bitumen from the free water knockout separator is sent directly to the upgrader for further processing to a WTI-grade oil. Hence, the diluent purchase is not included in the operating expenses for this scenario.

Dilbit is a blend of bitumen and a diluent. The addition of diluent allows dilbit to meet pipeline specifications for viscosity and density so that is can be pumped elsewhere for upgrading and refining.

Produced water from the free water knockout separator is cleaned in the produced water de-oiling system, which consists of three steps. Bulk oil and solids are first removed in a skim tank. Any remaining oil is further removed in an induced gas floatation cell. Finally, fine droplets and solids are removed in an oil removal filter.

The de-oiled produced water is combined with raw make-up water from the water reservoir and treated for use as boiler feed water in the produced water treatment system. Here, caustic is mixed into the water to raise the pH of the water to around 12.0. The water is then preheated to near boiling and passed through a de-aerator to remove non-condensable gases. The caustic, hot, de-aerated water is then fed to a first-stage evaporator, where a portion of the feed water is evaporated as a distillate. The distillate is collected and pumped to a boiler feed water tank for use in the steam generation process. A second-stage evaporator collects the brine waste from the first-stage system and concentrates it, recovering additional boiler feed-quality water. Taken together, the two evaporators recover 95–98% of the produced water feed. Evaporator waste brine is removed in a crystallizer process and shipped to a disposal facility; see Section 9.2.2.

Raw make-up water is pretreated by passing it through a cartridge filter and strong acid cation water softener.

Non-condensable gases include O_2 and CO_2.

Natural gas-fired water tube boilers are used to generate 943 psig (6500 kilopascals gauge or kPag) steam from the boiler feed water. Produced gas recovered from wellheads and from the free water knockout separator is used to reduce the amount of fuel purchased for the steam generator. Steam generated at the CPF is distributed through a manifold system to each wellhead so that injected steam is 667 psig (4600 kPag) and 99.5% quality.

The "g" after "psi" and "kPa" refers to gauge pressure or pressure relative to the local ambient pressure.

Electricity required for operating the CPF is provided by a cogeneration facility consisting of a natural gas-fired turbine and a heat recovery steam generator. In addition to providing electrical power for the CPF, waste heat from the turbine is used to generate additional steam for injection. Scaled to 10,000 BPD, the electricity required for the CPF is 9.84 MW.

The turbine generates 10% of the boilers' capacity.

Connacher states that the largest consumers of gas in their SAGD plant are the steam generators and cogeneration. The fuel used to power the electrical turbine accounts for 12% of the CPF's fuel use. The report does not state what portion of the remaining fuel use in the CPF can be attributed to the boiler system.

9.1.1.4 Service Facilities and Site Preparation

In addition to the major process steps outlined above, Connacher's design includes the following in its total project cost.

- Flaring systems
- Cooling and heating system
- Above ground interconnecting pipeline system
- Emulsion gathering system
- Vapor gathering system
- Gas distribution
- Emergency electrical power
- Sanitary and potable water system
- Utility steam
- Domestic sewage
- Drain system
- Compressed air system
- Fire and gas detection
- Storage tanks

Many of these components are covered by various factors in Seider's costing methodology [13], such as site preparation and service facilities costs. The estimates for these factors vary over a wide range. For the three previous scenarios in this report, the costs of site preparation (C_{site}) and of service facilities (C_{serv}) were each assumed to be 10% of C_{TBM} (see Table 5-4). In order to avoid the components already included in the overall Connacher costs from being double counted, for this scenario C_{site} and C_{serv} are each assumed to be 8% of C_{TBM}. Sensitivity of the supply cost to this assumption is explored in Section 9.3.4.

9.1.2 Fractionation and Primary Upgrading

Raw bitumen produced from in situ extraction requires primary upgrading to crack long hydrocarbon chains into lighter components, thus reducing its average molecular weight. The raw bitumen collected at the wellhead is fed to a fractionator where lighter components are separated from the heavier components. The heavier components are then fed to a delayed coker as described in Section 8.1.4 while the lighter distillation cuts are further processed in the secondary upgrading step. These distillation cuts are defined as:

The overall flowrate of bitumen to the delayed coker is 11,805 BPD.

- Naptha - hydrocarbons with a boiling range of 100º–400ºF (38º–204°C)
- VGO - hydrocarbons with a boiling range of 400º–950ºF (204º–510°C)
- Wax - hydrocarbons with a boiling range > 950ºF (510°C)

Each of these cuts is sent to a heated storage tank at the site of the hydrotreater to await further processing.

This unit operation is modeled based on costing data from Maples [14] using appropriate scaling rules; see Section 5.4.1. The production of CO_2 from coking and O_2 requirements for oxy-firing are both estimated from fuel requirements in the material balances data. Characteristics of the bitumen feed and coker yield are taken from data in Bunger et al. [15] and summarized below in Table 9-4. The coker yield is assumed to be 76.05 wt% liquid products, 7.41 wt% gaseous products, and 16.54 wt% coke. The gaseous products are captured and used for heating. Coke is collected and sold as fuel coke using price estimates from EIA [16].

These yields reflect increased gas production and reduced liquids production relative to Asphalt Ridge oil sands (Section 8.1.4).

Coke production averages 341 TPD (309 MTPD).

9.1.3 Secondary Upgrading

Upgraded oil from the coker via the fractionator requires a secondary upgrading step, hydrotreating, to reduce its aromatic, nitrogen, sulfur and heavy metal content. The upgrading process is the same as that for the ex situ oil shale scenario (Section 6.1.6): H_2 is reacted with the partially upgraded oil from the fractionator under the same process conditions and with the same catalysts. However, due to the reduced production rate and the differences in sulfur and nitrogen content of raw bitumen as compared to raw shale oil, the size of the units are smaller as less H_2 addition is required.

Each distillate cut is hydrotreated separately in its own catalytic reactor.

The total flowrate of oil (e.g. distillate cuts) to the hydrotreater is 8,978 BPD.

Aromatic components of the oil are converted to aliphatic components, nitrogen to NH_3, and sulfur to H_2S. Heavy metals are confined to the coke residue. Approximately 1,569 tons (1,423 metric tons) of H_2S and 2,649 tons (2,403 metric tons) of NH_3 are produced annually as byproducts of hydrotreating.

The hydrotreater is modeled with ProMax using properties of the distillate cuts from the primary upgrading step (see Table 9-4). The method of Guthrie (Section 5.4.1) is used to compute capital and operating costs from the detailed process flowsheet information. Hydrogen is provided by the hydrogen plant discussed in Section 9.1.4.

The properties of the raw and upgraded bitumen are given in Table 9-4; properties of three benchmark crudes are shown for comparison. The product of the primary upgrading step is labeled "Coker Yield." Because no data on hydrotreated P.R. Spring bitumen could be found, properties for Asphalt Ridge bitumen from Oblad et al. [17] are used for the hydrotreated oil. The upgraded bitumen ("Hydrotreater Yield") is of high quality with properties similar to those of the benchmark crudes, including an API approaching 32°, low pour point, and low sulfur, nitrogen, and heavy metal content.

Table 9-4. Properties of raw bitumen and upgraded synthetic crude oil in comparison to three benchmark crudes [15,17–19].

		Raw Bitumen	Coker Yield	Hydrotreater Yield	West Texas Intermediate	Brent Crude	Arabian Light
Oil Properties	API Gravity	10.3	26.5	31.68	39.6	38	34
	Sulfur (wt%)	0.75	0.29	0.0023	0.24	0.37	1.7
	Nitrogen (wt%)	1.0	0.57	0.05		0.1	0.07
	Pour Point (°F)				-18	45	-10
	Solids (wt%)						
Distillate Cuts	Boiling Range (°F)	(vol %)					
Naptha	100 - 400	7.9	12.4	20.3	56		
	104 - 800					78	67
Vacuum Gas Oil	400 - 950	32.5	73.6	71.3	32		
	800 +					21.7	32
Wax	950 +	59.6	14.0	8.4	9		
	1000 +					10.2	17

9.1.4 Hydrogen Plant

The quantity of H_2 needed for the secondary upgrading of bitumen is determined from the mass balances given in Equations 8.2–8.5, which account for the change in hydrogen, sulfur, and nitrogen content of the hydrotreater feed [15] and product [17]. Based on this mass balance, 441 SCF (12.5 cubic meters) of H_2 are needed to upgrade each barrel of oil from the coker. For comparison, bitumen upgrading for the ex situ oil sands scenario requires 412 SCF (11.7 cubic meters) of H_2 per barrel while upgrading of the shale oil from the ex situ oil shale process requires 2000 SCF (57 cubic meters) of H_2 per barrel.

The H_2 is supplied by a hydrogen plant of the same design as that used for the ex situ oil shale scenario shown in Figure 6.8 and discussed in Section 6.1.7. The size of the plant is similar to that for the ex situ oil sands scenario due to similar H_2 demand. The hydrogen plant is supplied by natural gas and steam for the steam.

The capital and operating costs for the hydrogen plant are determined by applying the economic and engineering scaling factors discussed in Section 5 to capital and utilities utilization data for a PSA-based H_2 production system from Fleshman [20]. In this scenario, the steam required by the upgrading process is generated in the CPF and the excess steam produced by the hydrogen plant is used for SAGD instead of being sold back to a steam utility plant.

As noted previously, the upgrading process requires 590 million pounds (268 million kilograms) of steam and produces 304 million pounds (138 million kilograms) of steam per year.

9.1.5 Ammonia Scrubber

Sour gases generated as byproducts in the hydrotreater are fed to a wet scrubber with dilute sulfuric acid to remove NH_3 as described in Section 6.1.8. Capital and operating expenses as well as ammonium sulfate sales are neglected in the cash flow analysis.

Ammonium sulfate production is estimated to be 10,276 tons (9,322 metric tons) annually.

9.1.6 Amine Treatment Unit

The amine treatment unit scrubs acid gas, e.g. H_2S, from the waste gas streams as described in Section 6.1.9. Capital and operating costs are scaled from data in Maples [14]. See Figure 9.6 for an overview of how this unit is integrated with the ammonia scrubber, sulfur recovery unit and sour water stripper.

9.1.7 Sulfur Recovery Unit

Acid gas streams are further stripped of H_2S in the sulfur recovery unit as described in Section 6.1.10. Elemental sulfur is the product and is produced at a rate of 1,402 tons (1,272 metric tons) per year. Capital and operating costs are scaled from data in Maples [14]. It is assumed that the sulfur recovery rate is 95 wt% and that all sulfur recovered is sold at market prices [21].

9.1.8 Sour Water Stripper

Fouled water from the fractionator and recycled cooling water from the hydrotreater (see Figure 9.6) is processed through a sour water stripper to remove dissolved contaminants as described in Section 6.1.11. The stripped water is then sent to the water reservoir (Section 9.2.5) for reuse. Capital and operating costs are scaled from data in Maples [14].

9.1.9 Delivery via Pipeline

The SCO is taken from product storage tanks at the upgrader and sent through a pipeline from P.R. Spring to North Salt Lake City. The pipeline path was shown in Figure 6.10. The total estimated pipeline length is 219 miles (352 kilometers).

An economical pipeline diameter of 4.4 inches (11 centimeters) was computed by optimizing the pumping requirements and costs using the method of Peters and Timmerhaus [22]. The capital costs for constructing the pipeline and pumping stations are estimated following the methodology used by Boyle [23]. Additional details about the pipeline are found in Section 6.1.12.

9.1.10 Cost of Utilities

In actual practice, this in situ scenario will have greater utility costs than the scenarios proposed in Sections 6, 7, 8 due to its remote location and lack of any nearby infrastructure. However, site factors for such a location were not available. Thus, the only utilities costs that account for the location are the infrastructure costs associated with bringing in water, electricity and natural gas.

With the exception of steam, the utilities required for this scenario and their prices are listed in Table 5-7: natural gas; electricity; process, cooling and boiler feed water; chemicals; O_2; and refrigerant. The electricity purchased from the grid is only for the upgrading process; SAGD uses a cogeneration facility to produce the electricity it requires (see Section 9.1.1.3). The costs for steam utilities (and the off-site steam plant) are supplanted by the SAGD steam generators, which are large enough to handle all of the steam required for upgrading. This scenario employs the constant utility prices in Table 5-7 with the exception of the profitability analysis using the NPV method, which uses EIA price forecasts to estimate natural gas and electricity prices [24].

The only additional cost applied to steam production for upgrading is the cost of purchasing makeup water.

Natural gas and electricity are brought in to the site from Vernal, Utah, a distance of approximately 43 miles (70 kilometers). Water for plant needs is pumped 33 miles (53 kilometers) from the Green River via pipeline to a reservoir at the plant site. Raw water from the reservoir (see Section 9.2.5) is treated such that it is suitable for use as process, cooling, and boiler feed water. The chemicals for water treatment and other purposes are trucked in and stored in a warehouse.

Refrigeration and O_2 (for oxy-fired processes related to upgrading only) are purchased from off-site utility plants at the per unit cost given in Table 5-7. Other than capital costs for construction, these prices are assumed to cover all of the costs/externalities of the utilities. Capital costs for constructing the water treatment and refrigeration plants are estimated from Seider et al. [13] and are listed in Table 5-5 under allocated costs for utility plants. Capital costs for the oxygen plant are excluded due to lack of data.

Infrastructure costs associated with bringing utilities to the site are accounted for in various ways. Costs associated with (1) building an electrical substation ($1.6 million), (2) establishing the electrical line, switching gear, and tap ($18.8 million), and (3) bringing in the natural gas line ($45.7 million) and establishing the metering hub ($1.0 million) have been obtained from Sage Geotech [25]. The costs of the water pipeline ($8.2 million) and the water reservoir ($1.1 million) have been estimated using standard construction and excavation cost estimation methods [23,26]. Warehousing costs of chemicals are accounted for in the percentage (8%) of C_{TBM} used for service facilities [13]; see Table 5-5 and Section 9.1.1.4.

Costs given here are for the air-fired case. For oxy-firing, the cost of the electrical substation increases to $2.1 million and the water pipeline increases to $8.3 million.

Scaled to 10,000 BPD, the electricity required for the CPF is 9.84 MW, which is 27% more electrical power than is required for upgrading. If this process were actually constructed in P.R. Spring, one possible design choice would be to expand the cogeneration facility to meet the electricity needs of the process instead of just the CPF. Scaling from capital cost estimates in EIA [27], the capital cost for a 17.6 MW conventional natural gas combined cycle electrical plant would be $71.0 million in 2012 US$. Assuming that the scaled capital costs from Connacher account for 9.84 MW of the 17.6 MW total, the cogeneration plant expansion would cost $31.3 million. While this cost exceeds the cost of connecting to the grid to handle the electricity demands of upgrading ($20.4 million), the waste heat would add additional steam production. Unfortunately, not enough information is available in Connacher's documentation [10,11] to add this design option to the analysis, so the cogeneration facility provides electricity only to the CPF for this scenario.

Scaling is performed by applying Williams' six-tenths rule [28] and adjusting for inflation with the CEPCI index (Table 5-6).

The total required generation capacity for both SAGD and upgrading is 17.6 MW.

9.1.11 Labor Utilization

Management, skilled labor and maintenance labor are required for all aspects of in situ oil sands production. Skilled labor and management requirements are considered in Table 9-5. The number of people employed to perform maintenance labor is excluded from the totals given in the table. Instead, the costs of maintenance labor are assumed to be covered by the yearly maintenance cost (5% of C_{TDC}).

The number of employees on a per shift basis is determined for each unit operation of the entire production process following the approach given by Seider et al. [13]. Assuming that five shifts per week are used for 24/7 operation, the total number of employees for this scenario with air-firing is 415. For oxy-firing, the total number of employees is 450.

Connacher [10] indicates that its 24,000 BPD SAGD expansion project will require 80 full time employees (neglecting construction). Assuming that these employees are split over five shifts, 16 employees are needed per shift to run the SAGD operation. Scaling linearly to this scenario's 10,000 BPD operating capacity would result in seven employees needed per shift for the "Steam

Table 9-5. Labor requirements for ex situ oil sands extraction (per shift).

These labor requirements are for the startup and production phases of the project and do not include labor required for construction of the various unit operations.

Process	Operators	Lab & Engineering	Management
Steam Generator	10	2	1
Delayed Coker	14	2	1
Hydrotreater	18	2	1
H_2 Plant	6	2	1
Sour Water Stripper	4	2	1
Amine Treatment Unit	4	2	1
Sulfur Recovery Unit	6	2	1
Total	**62**	**14**	**7**
- - - - - - - - - - - - - - - - - - - -	*Oxy-Fired Only*	- - - - - - - - - - - - - - - - - - - -	
CO_2 Compressor	4	2	1
Total	**66**	**16**	**8**

Generator" unit operation listed in Table 9-5. Due to the uncertainty in the labor required, the sensitivity of oil supply price to the number of employees is analyzed in Section 9.3.5.

9.2 Environmental Aspects of In Situ Oil Sands Scenario

Because in situ production does not require rock removal and tailings disposal, waste effluents are vastly reduced compared to ex situ operations with similar operating capacity. Nevertheless, in situ production will have an impact on land, water, and air. In a recent report by the Pembina Institute [29], it was estimated that in a new, state-of-the-art SAGD operation, over 8% of the total lease area would be cleared for SAGD infrastructure. In addition, makeup water must be supplied from a local water source; there is potential damage to ecosystems caused by roads, other industrial features, and wastes of various types; and GHG emissions will increase compared to the ex situ oil sands scenario due to the energy required for steam production. While the profitability analysis for this scenario does not include the cost of externalities associated with visual impairment, effects on ground and surface water quality, or ecosystem damage caused by SAGD infrastructure, the costs of some air pollution control, disposal of waste effluents, reclamation, carbon management, and water management are accounted for as described below.

9.2.1 Air Pollution Control

This scenario includes the costs of removing H_2S from the various sour gas streams generated by the upgrading of oil sands bitumen; see Sections 9.1.6 and 9.1.7. Capital and operating expenses for removing NH_3 are assumed to be offset by the sale of ammonium sulfate; see Section 9.1.5. All other capital costs for air pollution control equipment are assumed to be covered by this scenario's contingency cost, which is $115 million.

9.2.2 Disposal of Waste Effluents

The Connacher report [10] includes a waste management plan for waste effluents ranging from process blowdown water to pallets to sludge from separators and oil slop tanks; many are recycled or recovered in some way.

However, itemized operating costs for managing each of these wastes are not given. Hence, costs for handling these various waste streams are not included in this scenario's analysis.

This analysis does include the cost of disposal of crystallizer brine waste slurry, a waste stream resulting from the removal of salts from the bitumen-water slurry that is pumped from the producer wells. This high solid waste (50% by weight solids) is trucked off-site to an approved disposal facility. Scaling the mass of the Connacher waste stream by the reduced production rate of this scenario yields an estimate of 54.2 tons (49.2 metric tons) per day of brine waste slurry requiring disposal. Using the estimate of Seider et al. [13] of $0.06 per dry pound to dispose of nonhazardous dry or wet solids, the cost of disposal is $1.2 million per year.

9.2.3 Reclamation Costs

Based on data presented by Andersen et al. [30] for reclamation of orphaned oil and gas wells in Wyoming (see discussion in Section 7.2.2), this scenario assumes well reclamation costs of $29,600 per well (inflated from 2008 to 2012 US$ using a 1.8% inflation rate). Given the 96 well pairs required for this scenario, the total reclamation cost for all wells is $6.3 million.

9.2.4 Carbon Management

Two different combustion systems with different carbon emissions strategies are considered to supply heat for various unit operations that make up the primary and secondary upgrading processes: conventional (air-fired) combustion and oxy-combustion. Two cases are considered for the conventional combustion system: (1) no tax on CO_2 and (2) a $25 per ton tax on CO_2. The oxy-combustion system produces a nearly pure CO_2 stream that is compressed to pipeline conditions and sold at a price of $25 per ton. The costs of the oxy-combustion, gas clean up, and CO_2 compression systems are partially offset by the sales price of CO_2.

With the information available from Connacher [10,11], it is not possible to estimate the additional costs associated with switching to oxy-firing for SAGD steam production.

The equipment for the two types of combustion systems is costed in ProMax and then rolled into the hydrotreater cost. The costs for CO_2 compression are determined from a regression fit of costs for compressor systems at various scales; see Section 6.2.3. The O_2 required for oxy-firing is purchased from a supplier at the price per ton listed in Table 5-7. The costs of a CO_2 pipeline are assumed to be the responsibility of the purchaser and are not included in the present analysis.

For both the air- and oxy-fired cases, GHG emissions, including CO_2, CH_4, and N_2O, are produced from: the heating and electricity requirements associated with SAGD, the delayed coker, the hydrogen plant, and the hydrotreater; drilling; off-site steam and electricity generation, including that required for the air separation unit that supplies the O_2 for oxy-firing; and product transport to the refinery. For the air-fired combustion system, the total CO_2e emissions from these sources are 742,900 tons (702,400 metric tons) per year. For the oxy-combustion system, 782,500 tons (709,900 metric tons) per year of CO_2 are produced, but only 194,400 tons (176,400 metric tons) are of a quality that can be sold to a pipeline because the oxy-firing option is only considered for primary and secondary upgrading. The GHG totals for both air- and oxy-fired systems also neglect GHG emissions associated with facilities construction, refrigeration, and water treatment.

CO_2e emissions are the sum of CO_2, CH_4, and N_2O emissions on a basis equivalent to CO_2 emissions.

Steam production accounts for 55% of total CO_2 production for air-fired in situ production/upgrading.

Oxy-firing with CO_2 capture was not analyzed for the SAGD process because detailed information necessary to do the analysis was not available.

9.2.5 Water Management

Each part of SAGD production and bitumen upgrading generates water, consumes water, or is water neutral as a result of recycling. Water usage is estimated using a material balance around the entire scenario. Table 9-6 summarizes water usage for both the air- and oxy-fired in situ oil sands scenarios.

See the generic water balance shown in Figure 6.12.

Table 9-6. Itemized water balance for ex situ oil sands production with air- and oxy-firing; data obtained from various sources [11,14, 20] and from Promax simulations.

This table does not include water needed for reclamation.

Category	Item	Water (bbl / bbl of oil)		Water (acre-ft/yr)	
		Air-Fired	Oxy-Fired	Air-Fired	Oxy-Fired
Recycled	Cooling Water				
	SAGD	4.49	4.49	2,111	2,111
	Delayed Coker	0.03	0.03	13	13
	Hydrotreater	0.12	0.12	57	57
	H_2 Plant	0.49	0.49	230	230
	Sulfur Recovery Unit	0.04	0.04	19	19
	CO_2 Compressor	-	8.68	-	4,085
	Boiler Feed Water				
	Sulfur Recovery Unit	0.01	0.01	3	3
	Steam	0.46	0.46	217	217
	Subtotal	**5.63**	**14.32**	**2,650**	**6,735**
Consumed	SAGD	0.31	0.31	147	147
	H_2 Plant	0.17	0.17	82	82
	Upgrading				
	Cooling Tower Makeup	0.03	0.29	14	137
	Steam Recycle Losses	0.01	0.01	7	7
	Subtotal	**0.53**	**0.79**	**250**	**372**
Generated	CO_2 Compressor	-	0.25	-	117
	Subtotal	**-**	**0.25**	**-**	**117**
Water In		**0.53**	**0.54**	**250**	**255**

The process units listed in the "Recycled" category use water as a heat transfer medium. Water flow rates for the units listed under "Cooling Water" are determined from process flowsheet calculations in ProMax (hydrotreater and CO_2 compressor), scaled from literature values (Maples [14] for sulfur recovery unit and Fleshman [20] for the hydrogen plant), or scaled from Connacher's estimates of recycled water volume from SAGD [11]. Water leaving these process units is sent to cooling towers before it is recycled. Water in the form of steam is recycled back to the CPF. Water in the "Consumed" category must be replaced with makeup water. SAGD water losses include losses to the reservoir (assumed to be 5% of steam injected) and losses in processing steps at the CPF (oil treatment, evaporator, crystallizer, and steam generation). In addition, the SAGD losses include a 25% contingency. Makeup water requirements for SAGD are obtained from Connacher [11]. Other water losses include evaporation in the cooling towers, assumed to be 3 wt% of the cooling water flow, and consumption for H_2 production, which is scaled from Fleshman [20]. Water in the "Generated" category is produced during the condensation of oxy-fired flue gases. The volume of condensed water produced is calculated based on the mass flow rate of CO_2 and assumptions of complete combustion and recovery of all water in the flue gases.

The total required makeup water for the air-fired case is 250 acre-feet per year (0.345 CFS or 0.0098 CMS). For the oxy-fired case, this number increases slightly to 255 acre-feet per year (0.352 CFS or 0.0100 CMS) due to the larger cooling water demand for the CO_2 compressor system which leads to increased recycle losses.

The largest water use in this scenario ("Consumed" category) is for SAGD operations at 0.31 bbl/bbl of oil produced. These SAGD water consumption numbers, scaled from Connacher [11], are much lower than other recent data. For example, in a report summarizing water usage by nine in situ oil sands operations in Alberta, the average total water consumption was 1.1 barrels of water per barrel of bitumen produced [31]. Nevertheless, even if the higher SAGD water consumption numbers are used, overall water consumption for in situ oil sands production and upgrading is much lower on a per barrel basis than either of the ex situ scenarios analyzed in this report.

The volume of water consumed for hydrogen production is the second largest category at 0.17 bbl/bbl of oil produced. Evaporation in the cooling towers, listed as "Cooling Tower Makeup" in Table 9-6, is assumed to consume 3 wt% of the "Recycled" water stream. Steam recycle losses for upgrading are based on Connacher's water balance (see Table B.6.1.1 in their report [11]), which estimates recycle losses of 3% by volume. As described in Section 6.2.4, other small water uses/losses are assumed to be negligible and are not included in the water accounting. Also, the volume of water required for the one-time filling of tanks for startup is not included in Table 9-6.

The source of water for this scenario is the Green River, which is 33 miles (53 kilometers) from the P.R. Spring site. The Green River's 65-year average daily flow rate in January, the lowest flow rate of the year, is 2,300 CFS (65.1 CMS) [32]. Hence, the makeup water flow rate represents less than 0.02% of the Green River's flow at its lowest level.

This flowrate is measured near Green River, Utah, the nearest upstream USGS monitoring site from the general location of P.R. Spring.

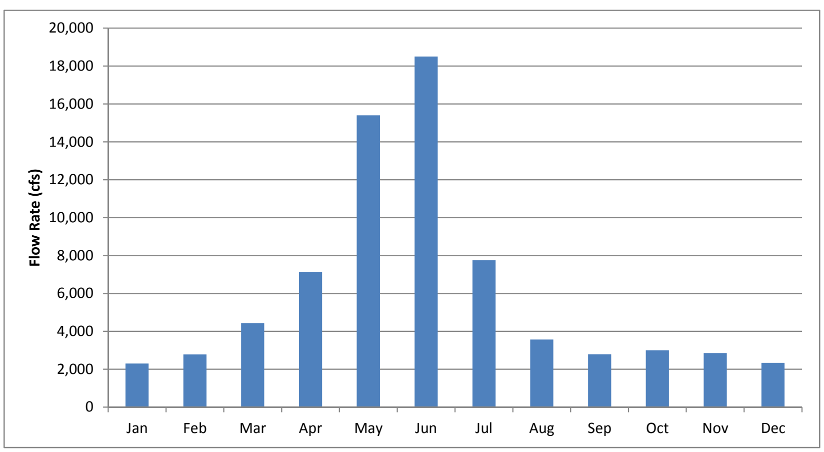


Figure 9.7: Average historical discharge from Green River by month near Green River, Utah [32].

The SAGD and bitumen upgrading processes require water on a daily basis plus a one-time filling of tanks for startup. Water is purchased at a rate of $50 per acre-foot per year (see Table 5-7) from those with agricultural water rights [33]. The purchased water is pumped from the Green River and transferred via a water pipeline to the plant site to fill the water storage reservoir for daily use. The capital and operating costs for the water pipeline are included in this analysis.

The size of the reservoir is determined by the duration of a prolonged drought in the area and the total water utilization for air-fired and oxy-fired processes as shown in Table 9-6. The estimated reservoir sizes are 62 acre-feet (75,900 cubic meters) for the air-fired case and 63 acre-feet (77,500 cubic meters) for the oxy-fired case. Costs for the lined water reservoir are computed using construction excavation costs that are applicable in the Uinta Basin [25]; they are estimated to be $1.1 million for both the air- and oxy-fired in situ oil sands operations.

A prolonged drought is considered to be 90 days; see Section 6.2.4.

9.3 Profitability Analysis of In Situ Oil Sands Production

All dollar values given in this section are reported as 2012 US$ unless otherwise noted. An inflation rate of 1.8% is used to adjust dollar values from other reports to 2012 US$, except for instances where more specific inflation indices are available.

The profitability analysis performed for this scenario was outlined in Section 6.3. It includes an estimation of capital costs, a "base case" Supply Price Method profitability analysis as a function of hurdle rate, an NPV profitability analysis based on EIA oil price forecasts and defined hurdle rates, and a Supply Price Method sensitivity analysis. Both the Supply Price Method and the NPV Method consider all the costs associated with SCO production as described in Section 5.4. All costs and profitability measures are reported in terms of real dollars.

Table 9-7 lists the key assumptions for the base in situ oil sands cases using air-fired and oxy-fired combustion for plant heating downstream of the SAGD facilities.

Table 9-7. Ex situ oil sands scenario base case assumptions.

Category	Input/assumption
Air- & oxy-fired	
SAGD	Bitumen saturation ≥ 6 wt%, bitumen recovery = 54%, initial reservoir pressure = 508–653 psi (3500–4500 kPa), reservoir depth = 1575 ft (480 m), pay zone thickness = 72 ft (22 m); from Connacher [11]
Drilling costs	Drilling accounts for 20% of total cost of SAGD project [12]; cost is $384,000 per well
Bitumen recovery	Coker - 76.05 wt% [15], Hydrotreater - 98.1 wt% (from ProMax flowsheet)
Utility pricing	Fixed prices from Table 5-7 with two exceptions: (1) all steam requirements included in SAGD costs, (2) electricity for SAGD included in fuel costs, electricity for other processes uses fixed prices from Table 5-7
Hurdle Rate	0–12%
Taxes and Royalties	Federal: 35% of Taxable Income State: 5% of Taxable Income Property: 1% of Total Permanent Investment Severance[a]: 3–5% of Adjusted Wellhead Price Conservation Fee: 0.2% of Adjusted Wellhead Price Oil Royalty[a]: 8–12.5% of Oil Sales
Product	WTI-quality SCO
Air-fired	
CO_2 tax	None
Revenue	Oil, coke, sulfur, and steam
Oxy-fired (upgrading only)	
CO_2 sales	$25/ton
Revenue	Oil, CO_2, coke, sulfur, and steam

[a] *See Section 5.4.3 for scenario accounting details related to tax and royalty rates.*

Table 9-8 lists the major outputs from and inputs to the in situ production of SCO from oil sands on a per barrel basis. The CO_2 output from the air-fired scenario is 60% higher than the output from the ex situ scenario (air-fired) due to the CO_2 penalty of heating the ground with steam. The tradeoff is that because the bitumen is produced in situ, there is not a large waste stream of oil sand tailings as with the ex situ oil sands scenario. Also, the CO_2 from the air-fired scenario is dilute and is emitted into the atmosphere while the CO_2 from the oxy-fired scenario is captured, is of pipeline-quality, and can be sold. Lastly, the mass of petroleum coke produced in the delayed coker using this P.R. Spring bitumen as the feedstock is nearly 50% greater than the mass of coke produced with Asphalt Ridge bitumen as the feedstock (Section 8). The difference in coke production for these two bitumens is taken directly from data in Bunger et al. [15].

Table 9-8. Major process outputs and inputs on a per barrel basis.

Category	Item	Air-Fired	Oxy-Fired	(Units) / bbl of oil
Outputs	Ammonium Sulfate	5.63	5.63	lb
	CO_2 [a]			
	Emitted to Atmosphere	409	324	lb
	Sold to Pipeline	-	107	lb
	Steam (600 psig, 700°F)	83	83	lb
	Petroleum Coke	68	68	lb
	Sulfur	0.77	0.77	lb
	Waste Disposal [b]	5.42	5.42	lb
Inputs	Catalyst	0.02	0.02	lb
	Electricity	18.65	25.14	kWh
	Fuel [c]			
	Purchased	2.18	2.17	MMBtu
	Total	3.06	3.05	MMBtu
	Makeup Water	0.53	0.54	bbl
	O_2	-	109	lb
	Refrigerant	13.58	13.58	MJ
	Steam			
	50 psig	232	232	lb
	450 psig	383	383	lb
	SAGD	1,569	1,569	lb

[a] *The per barrel CO_2 output is CO_2e. These emissions do not include facilities construction, refrigeration, or water treatment. Also, CO_2 emissions from the CPF are not captured in the oxy-fired scenario.*

[b] *Mass of solids in brine disposed of from the CPF crystallizer; see Section 9.2.2 for details.*

[c] *Difference between the amount of fuel (e.g. natural gas) purchased and the fuel total is the captured heating value of gases from the delayed coker.*

On the input side, the steam requirement for SAGD is more than double that for upgrading. Also, the oxy-fired case has O_2 as a required input and increased electricity usage relative to the base case due to the power consumption of the CO_2 compression system. Compared with the ex situ oil sands scenario, fuel requirements are more than double while water use decreases by a factor of five. The fuel increase is driven by the energy requirements of steam production. The decrease in water use is the result of not having a mining operation where water is lost to the sand tailings.

9.3.1 Capital Costs for In Situ Oil Sands Extraction

The total capital investment for the complete SAGD facility and an air-fired upgrading plant is \$1.300 billion; that of the SAGD facility and an oxy-fired upgrading plant is \$1.328 billion. A breakdown of all capital costs is shown in Table 9-9; definitions for all cost categories can be found in Section 5.3.4. The largest capital cost for the air-fired heating system is for SAGD (e.g. "Steam Generator" in the table) at 25% of the total capital cost. Other large capital cost categories include the hydrotreater at 10% and drilling at 7%. These percentages are only slightly changed for the oxy-fired case with the exception of the utility plants and water reservoir.

Table 9-9. Capital cost breakdown by unit for the base case in situ oil sands scenario in millions of 2012 US\$.

Category	Item	Air-fired	Oxy-fired
Total Bare Module Investment - C_{TBM}	Steam Generator	\$ 328.7	\$ 328.7
	Delayed Coker	\$ 66.1	\$ 66.1
	Hydrotreater	\$ 123.5	\$ 125.8
	H_2 Plant	\$ 13.3	\$ 13.3
	Sour Water Stripper	\$ 6.6	\$ 6.6
	Amine Treatment Unit	\$ .5	\$ .5
	Sulfur Recovery Unit	\$ 1.3	\$ 1.3
	CO_2 Compressor	\$ -	\$ 9.9
	C_{TBM} Subtotal	**\$ 540.0**	**\$ 552.2**
Total Direct Permanent Investment - C_{DPI}	Site Preparation	\$ 43.2	\$ 44.2
	Service Facilities	\$ 43.2	\$ 44.2
	Oil Pipeline	\$ 63.1	\$ 63.1
	Water Pipeline	\$ 8.2	\$ 8.3
	Water Reservoir	\$ 1.1	\$ 1.1
	Allocated Costs for Utility Plants	\$ 67.3	\$ 68.8
	C_{DPI} Subtotal	**\$ 766.2**	**\$ 781.9**
Total Depreciable Capital - C_{TDC}	Contingency	\$ 114.9	\$ 117.3
	C_{TDC} Subtotal	**\$ 881.1**	**\$ 899.2**
Total Permanent Investment - C_{TPI}	Land	\$ 17.6	\$ 18.0
	Permitting	\$ 6.4	\$ 6.4
	Royalties for Intellectual Property	\$ 17.6	\$ 18.0
	Startup	\$ 88.1	\$ 89.9
	Investment Site Factor	\$ 1.15	\$ 1.15
	Drilling	\$ 82.2	\$ 82.2
	Well Reclamation	\$ 6.3	\$ 6.3
	C_{TPI} Subtotal - US Midwest	**\$ 1,250.9**	**\$ 1,274.7**
Total Capital Investment - C_{TCI}	Working Capital	\$ 49.0	\$ 53.1
	Total (\$)	**\$ 1,299.9**	**\$ 1,327.8**

The CPFB is \$129,988 for the air-fired case and \$132,777 for the oxy-fired case. These numbers can be compared to the estimated capital costs of SAGD and standalone upgrading oil sands projects in Canada published in a 2008 CERI report [34]. The CPFB of the four 10,000-BPD commercial SAGD operations listed in the report ranges from \$28,573–\$32,969. The CPFB of the four standalone upgrading projects with production levels between 50,000–100,000 BPD ranges from \$35,748–\$59,943. The combined CPFB for SAGD plus upgrading for commercial projects in Canada ranges from \$64,322–\$92,913. Hence, the base case CPFB estimates for this in situ oil sands

One of the commercial projects included in the CERI report is the Connacher Great Divide project that was used as the basis for the SAGD analysis in this section.

CERI reports numbers in C\$. To convert to US\$, an exchange rate of 1:1 is assumed. Numbers have also been adjusted to 2012 US\$ using the CEPCI index.

scenario using SAGD capital costs scaled from Connacher and upgrading costs as described above are $40,000–$65,000 higher than those from commercial-scale Canadian projects. These higher CPFB values are largely driven by the scaling laws that have been applied (see Section 5.4.1) and by the reduced economies of scale for the much smaller (10,000 BPD) upgrading facility .

9.3.2 Supply Price Evaluation of In Situ Oil Sands Base Case

The supply price at a specified hurdle rate is computed by finding the real fixed price that results in NPV = 0 with the discount factor computed from the hurdle rate; see Section 5.2.2 for additional details.

9.3.2.1 Base Case Supply Prices

The base case supply price as a function of hurdle rate is given in Table 9-10 for air-fired combustion and in Table 9-11 for oxy-fired combustion. All supply costs listed in these two tables are positive contributors to the supply price while all non-oil revenue streams are negative contributors. The supply costs from Table 9-10 are plotted in Figure 9.8 while the supply costs from Table 9-11 are plotted in Figure 9.9.

See Section 5.2.2 for details on how supply price is determined.

Oxy-firing is considered only for the unit operations associated with upgrading, not for SAGD; see Section 9.2.4.

Table 9-10. Supply price for air-fired in situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Drilling	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29
SAGD	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83	$ 16.83
Upgrading [a]	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31	$ 15.31
Taxes	$ 11.10	$ 13.77	$ 17.10	$ 20.90	$ 25.19	$ 30.38	$ 36.31
Oil Royalties	$ 8.92	$ 9.83	$ 10.92	$ 12.16	$ 13.57	$ 15.20	$ 17.05
Net Earnings	$ -	$ 4.94	$ 10.70	$ 17.29	$ 24.72	$ 33.19	$ 42.71
Maintenance	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87	$ 13.87
Other [b]	$ 18.27	$ 18.33	$ 18.40	$ 18.48	$ 18.57	$ 18.68	$ 18.79
Supply Cost	**$ 85.59**	**$ 94.18**	**$ 104.41**	**$ 116.13**	**$ 129.35**	**$ 144.75**	**$ 162.17**
Other Revenue	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
Oil Supply Price	**$ 83.93**	**$ 92.52**	**$ 102.76**	**$ 114.47**	**$ 127.70**	**$ 143.10**	**$ 160.52**

[a] *"Upgrading" includes all costs associated with the delayed coker, hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, and sulfur recovery unit.*

[b] *"Other" includes all costs associated with the oil pipeline, water pipeline, allocated costs for utility plants, water reservoir, site preparation, service facilities, contingency, permitting, research, administration, incentive compensation, insurance, intellectual property royalties, overhead, land, startup, and CO_2 compressor (oxy-firing only).*

Table 9-11. Supply price for oxy-fired in situ oil sands production scenario as a function of hurdle rate.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Drilling	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29	$ 1.29
SAGD	$ 16.81	$ 16.81	$ 16.81	$ 16.81	$ 16.81	$ 16.81	$ 16.81
Upgrading	$ 19.18	$ 19.18	$ 19.18	$ 19.18	$ 19.18	$ 19.18	$ 19.18
Taxes	$ 11.34	$ 14.08	$ 17.48	$ 21.37	$ 25.76	$ 31.07	$ 37.12
Oil Royalties	$ 9.49	$ 10.42	$ 11.53	$ 12.81	$ 14.24	$ 15.91	$ 17.80
Net Earnings	$ -	$ 5.06	$ 10.95	$ 17.68	$ 25.29	$ 33.94	$ 43.67
Maintenance	$ 14.16	$ 14.16	$ 14.16	$ 14.16	$ 14.16	$ 14.16	$ 14.16
Other	$ 20.01	$ 20.07	$ 20.14	$ 20.22	$ 20.32	$ 20.43	$ 20.55
Supply Cost	**$ 92.27**	**$ 101.07**	**$ 111.54**	**$ 123.53**	**$ 137.05**	**$ 152.79**	**$ 170.58**
Other Revenue	$ 2.99	$ 2.99	$ 2.99	$ 2.99	$ 2.99	$ 2.99	$ 2.99
Oil Supply Price	**$ 89.28**	**$ 98.09**	**$ 108.56**	**$ 120.54**	**$ 134.06**	**$ 149.80**	**$ 167.59**

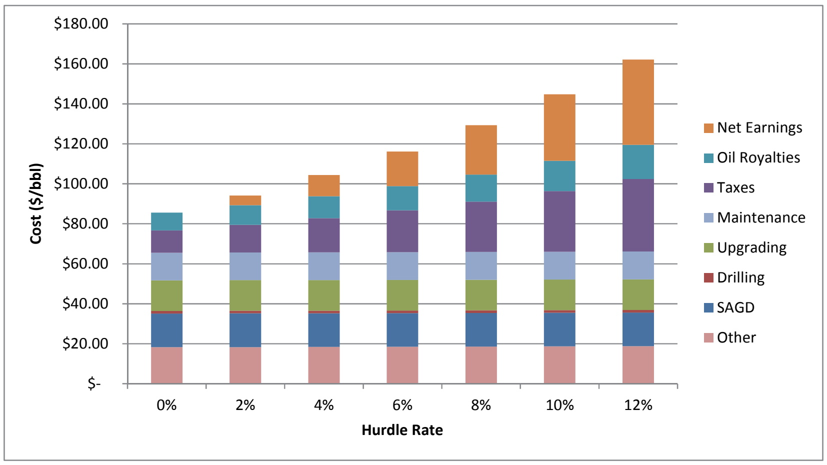


Figure 9.8: Supply cost for air-fired in situ oil sands production scenario as a function of hurdle rate.

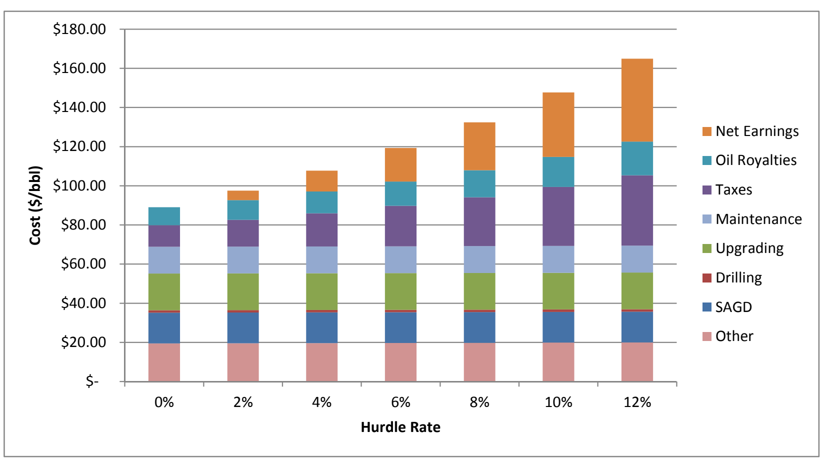


Figure 9.9: Supply cost for oxy-fired in situ oil sands production scenario as a function of hurdle rate.

The supply price to produce refinery-ready SCO is \$83.93–\$160.52/bbl for the air-fired case and \$89.28–\$167.59/bbl for the oxy-fired case. These supply prices include all costs (capital and operating expenses, taxes, royalties, net earnings computed from the hurdle rate) and all non-oil revenue streams. The supply cost at a hurdle rate of 0% is the cost of the project without any investor profit. The capture of CO_2 increases costs by \$6.68–\$8.41/bbl depending on the hurdle rate while the sale of CO_2 nets only \$1.33/bbl. Taxing CO_2 at the rate of \$25 per ton increases the base case supply price for air-firing by \$4.68 to \$88.62/bbl at a 0% hurdle rate, which is still less than the \$89.28/bbl supply price for oxy-firing (0% hurdle rate). CO_2 would have to be taxed at approximately \$29 per ton for the supply price of the air- and oxy-fired systems to be equal.

For the air-fired case at a 0% hurdle rate, the highest costs are for SAGD (\$16.83/bbl), upgrading (\$15.31/bbl), and maintenance (\$13.87/bbl). At a 12% hurdle rate, the highest cost categories are net earnings (\$42.71/bbl) and taxes (\$36.31/bbl), with royalties a distant third at \$17.05/bbl. Taxes are tied to net earnings, which rise with increasing hurdle rate; see Figure 9.10 in Section 9.3.2.2. When switching from an air-fired to an oxy-fired system, the only cost category (0% hurdle rate) that increases significantly is upgrading, with costs rising \$3.87/bbl. Hence, upgrading is the highest cost category (0% hurdle rate) for oxy-firing (\$19.18/bbl), followed by SAGD (\$16.81/bbl) and maintenance (\$14.16/bbl). At a 12% hurdle rate, the highest cost categories for oxy-firing are net earnings (\$43.67/bbl) and taxes (\$37.12/bbl).

The SAGD per barrel cost for oxy-firing is slightly lower than that for air-firing because of how fuel costs are attributed. Overall fuel consumption is slightly lower when using oxy-firing in the upgrader, but the fuel credit for produced gas from SAGD and the delayed coker is the same for both air- and oxy-firing. As a result, slightly less gas must be purchased with an oxy-fired upgrader.

9.3.2.2 Supply Costs that Vary with Hurdle Rate

Figure 9.10 shows the supply costs that are a function of hurdle rate as they are tied to the price of oil. All other costs listed in Tables 9-10 and 9-11 are fixed with respect to hurdle rate. State and federal corporate income taxes and incentive compensation are zero until the oil price reaches about \$54/bbl, at which price cash flow during production years becomes positive. The net earnings stay negative until oil sells for at least \$84/bbl for the air-fired base case and \$89/bbl for the oxy-fired base case; see the supply price for a 0% hurdle rate in Tables 9-10 and 9-11. At these respective oil prices, NPV = 0.

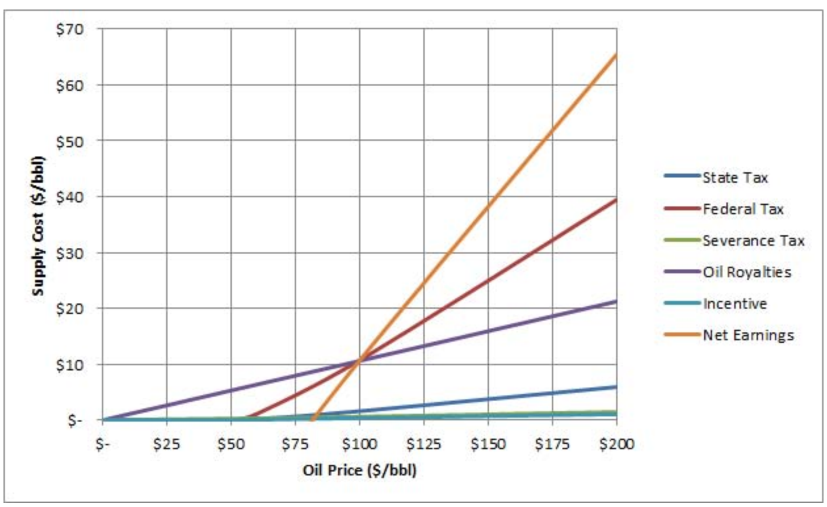


Figure 9.10: Supply cost (\$/bbl) of cost components that are dependent on oil price.

"Incentive" refers to incentive compensation, part of the "Other" category in Tables 9-10 and 9-11.

9.3.2.3 Detailed Supply Price Breakdowns

Detailed supply price breakdowns for both air- and oxy-firing at a 0% hurdle rate are given in Tables 9-12 and 9-13. Due to rounding error, the "Total" column may differ from the sum across any given row by $0.01. Also, fuel cost in these tables refers only to natural gas and does not include diesel or other types of fuels that might be necessary to operate equipment, vehicles, etc. With the exception of the supply costs tied to the price of oil, shown in Figure 9.10, all costs listed in Tables 9-12 and 9-13 are fixed with respect to hurdle rate.

Table 9-12. Detailed supply price breakdown for air-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Drilling	$ 1.29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.29
	SAGD	$ 5.95	$ 1.22	$ -	$ 9.63	$ 0.03	$ -	$ -	$ -	$ 16.83
Upgrading	Delayed Coker	$ 1.20	$ 1.70	$ 0.25	$ 0.69	$ 0.00	$ -	$ -	$ -	$ 3.84
	Hydrotreater	$ 2.24	$ 2.19	$ 0.45	$ 1.17	$ 0.00	$ -	$ -	$ 0.08	$ 6.12
	H_2 Plant	$ 0.24	$ 0.73	$ 0.01	$ 2.48	$ 0.02	$ -	$ -	$ -	$ 3.48
	Sour Water Stripper	$ 0.12	$ 0.49	$ 0.01	$ -	$ 0.00	$ -	$ -	$ -	$ 0.62
	Amine Treatment Unit	$ 0.01	$ 0.49	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.49
	Sulfur Recovery Unit	$ 0.02	$ 0.73	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.75
Delivery	Oil Pipeline	$ 1.14	$ -	$ 0.29	$ -	$ -	$ -	$ -	$ -	$ 1.44
Other	Water Pipeline	$ 0.15	$ -	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ 0.23
	CO_2 Compressor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes				
Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 1.22
		R-134a	Water Reservoir	$ 0.02
			Site Preparation	$ 0.78
	** Taxes includes:	State Tax	Service Facilities	$ 0.78
		Federal Tax	Contigency	$ 2.08
		Severance Tax	Permitting	$ 0.12
		Property Tax	Maintenance	$ 13.87
			Overhead	$ 3.32
			Research	$ 0.74
			Administration	$ 1.01
			Incentive Compensation	$ 0.25
			Insurance	$ 1.58
			Taxes**	$ 11.10
			Royalties - Oil	$ 8.92
			Royalties - IP	$ 2.37
			Working Capital	$ -
			Well Reclamation	$ 0.10
			Waste Disposal	$ 0.33
			Land	$ 0.32
			Startup	$ 1.60
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 85.59**
			CO_2	$ -
			Export Steam	$ -
			Petroleum Coke	$ 1.62
			Sulfur	$ 0.03
		Non-Oil Revenue Subtotal		**$ 1.66**
Oil Supply Price				**$ 83.93**

Table 9-13. Detailed supply price breakdown for oxy-fired base case scenario (0% hurdle rate).

Category	Item	Capital	Labor	Electricity	Fuel	Water	Steam	O_2	Other*	Total
Extraction	Drilling	$ 1.29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.29
	SAGD	$ 5.95	$ 1.21	$ -	$ 9.62	$ 0.03	$ -	$ -	$ -	$ 16.81
Upgrading	Delayed Coker	$ 1.20	$ 1.70	$ 0.25	$ 0.69	$ 0.00	$ -	$ 0.92	$ -	$ 4.75
	Hydrotreater	$ 2.28	$ 2.19	$ 0.51	$ 1.15	$ 0.00	$ -	$ 1.47	$ 0.08	$ 7.68
	H_2 Plant	$ 0.24	$ 0.73	$ 0.01	$ 2.44	$ 0.01	$ -	$ 1.44	$ -	$ 4.87
	Sour Water Stripper	$ 0.12	$ 0.49	$ 0.01	$ -	$ 0.00	$ -	$ -	$ -	$ 0.62
	Amine Treatment Unit	$ 0.01	$ 0.49	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.49
	Sulfur Recovery Unit	$ 0.02	$ 0.73	$ 0.00	$ -	$ 0.00	$ -	$ -	$ -	$ 0.75
Delivery	Oil Pipeline	$ 1.14	$ -	$ 0.29	$ -	$ -	$ -	$ -	$ -	$ 1.44
Other	Water Pipeline	$ 0.15	$ -	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ 0.23
	CO_2 Compressor	$ 0.18	$ 0.49	$ 0.31	$ -	$ 0.03	$ -	$ -	$ 0.15	$ 1.15

Notes	* Other includes:	Catalyst	Allocated Costs for Utility Plants	$ 1.25
		R-134a	Water Reservoir	$ 0.02
			Site Preparation	$ 0.80
	** Taxes includes:	State Tax	Service Facilities	$ 0.80
		Federal Tax	Contigency	$ 2.12
		Severance Tax	Permitting	$ 0.12
		Property Tax	Maintenance	$ 14.16
			Overhead	$ 3.45
			Research	$ 0.74
			Administration	$ 1.07
			Incentive Compensation	$ 0.25
			Insurance	$ 1.61
			Taxes**	$ 11.34
			Royalties - Oil	$ 9.49
			Royalties - IP	$ 2.58
			Working Capital	$ -
			Well Reclamation	$ 0.10
			Waste Disposal	$ 0.33
			Land	$ 0.33
			Startup	$ 1.63
			Net Earnings	$ -
		Supply Costs Subtotal		**$ 92.27**
			CO_2	$ 1.33
			Export Steam	$ -
			Petroleum Coke	$ 1.62
			Sulfur	$ 0.03
		Non-Oil Revenue Subtotal		**$ 2.99**
Oil Supply Price				**$ 89.28**

Fuel costs are significantly higher for this scenario compared to the ex situ scenario ($13.06 versus $6.01 for the air-fired cases) due to the heating requirements needed to make steam for SAGD. Additionally, some of the impact of location on infrastructure costs can be seen by comparing the "Allocated Costs for Utility Plants" for this scenario with those in Tables 8-13 and 8-14 of Section 8. The cost for this scenario (air-fired) is $1.25/bbl while that for the ex situ oil sands scenario is $0.30/bbl. This impact is also noted when comparing the capital costs for the oil and water pipelines. For this scenario (air-fired), the per barrel costs are $1.14 and $0.15, respectively. For the ex situ oil sands scenario, the per barrel costs are $0.80 and $0.07, respectively.

Natural gas usage for the air-fired scenario is 3.23 GJ/bbl, 2.30 GJ/bbl of which must be purchased.

Nevertheless, the cost burden of location is small compared with other cost categories.

The increased cost for oxy-firing is mostly due to the cost of O_2 (\$3.83/bbl) with small increases also noted for the capital, electricity, and labor needed for the CO_2 compression system. However, because the SAGD process is excluded from the oxy-firing system (see Section 9.2.4), it is not possible to analyze the full impact of switching to oxy-firing for all heating systems.

The costs of purchasing, delivering, and treating water are minimal (\$0.30/bbl and \$0.32/bbl for air- and oxy-firing, respectively). Even if the cost of water were to increase by an order of magnitude to \$500 per acre-foot per year (base case cost is \$50 per acre-foot per year), water costs would only increase by \$0.03/bbl to \$0.30/bbl and \$0.33/bbl for air - and oxy-firing, respectively. The larger water issue with respect to the P.R. Spring location is whether or not a 33-mile (53-kilometer) water pipeline could be built from the Green River due to land ownership/permitting issues and if not, could water be obtained in the near vicinity from wells.

Total water costs can be determined by adding up the "Water" column entries, the "Water Pipeline" row entries, and the "Water Reservoir" entry.

9.3.3 Supply Price Evaluation for Production of Bitumen

The supply prices given in the previous section are for producing SCO delivered to refining markets in Salt Lake City. In this section, supply prices for producing bitumen at the plant gate are determined by zeroing out the costs associated with upgrading and delivery in the Supply Price Method as described in Section 6.3.3. The supply costs by category are listed in Table 7-14 as a function of hurdle rate. The supply price is the same as the supply cost as there are no non-oil revenue streams.

Excluded costs are those for the hydrotreater, hydrogen plant, sour water stripper, amine treatment unit, sulfur recovery unit, CO_2 compressor (if applicable), and oil pipeline. Included costs are those for SAGD recovery of bitumen with associated CPF and cogeneration facility, water pipeline, reservoir, and all cost categories that are functions of other costs (service facilities, site preparation, land purchase, utility plants, etc.).

Plant gate supply costs do not include the cost of treatment of waste streams.

Table 9-14. Plant gate bitumen supply cost/price as a function of hurdle rate for ex situ oil sands production.

Hurdle Rate	0%	2%	4%	6%	8%	10%	12%
Drilling	\$ 1.29	\$ 1.29	\$ 1.29	\$ 1.29	\$ 1.29	\$ 1.29	\$ 1.29
SAGD	\$ 16.92	\$ 16.92	\$ 16.92	\$ 16.92	\$ 16.92	\$ 16.92	\$ 16.92
Upgrading	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Taxes	\$ 6.93	\$ 8.54	\$ 10.50	\$ 12.75	\$ 15.34	\$ 18.45	\$ 22.11
Oil Royalties	\$ 5.22	\$ 5.77	\$ 6.41	\$ 7.15	\$ 8.00	\$ 8.98	\$ 10.11
Net Earnings	\$ -	\$ 2.96	\$ 6.39	\$ 10.33	\$ 14.78	\$ 19.86	\$ 25.62
Maintenance	\$ 8.22	\$ 8.22	\$ 8.22	\$ 8.22	\$ 8.22	\$ 8.22	\$ 8.22
Other	\$ 10.03	\$ 10.07	\$ 10.11	\$ 10.16	\$ 10.21	\$ 10.27	\$ 10.35
Supply Cost	**\$ 48.61**	**\$ 53.76**	**\$ 59.85**	**\$ 66.82**	**\$ 74.77**	**\$ 84.00**	**\$ 94.63**
Other Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Oil Supply Price	**\$ 48.61**	**\$ 53.76**	**\$ 59.85**	**\$ 66.82**	**\$ 74.77**	**\$ 84.00**	**\$ 94.63**

The cost of upgrading, transportation to market, and treatment of waste streams can be estimated by comparing supply costs in Table 9-10 with those in this table. The difference in supply cost at a 0% hurdle rate is \$36.98/bbl. This supply cost difference increases with hurdle rate due to the impact of cost categories that are linear functions of hurdle rate such as taxes, royalties, and net earnings.

The bitumen supply prices in Tables 9-10 and 9-14 are illustrative of the range of supply prices that one might obtain for an in situ oil sands operation depending on what costs are included in the calculation, what the product is assumed to be, and the accessibility/location of the market for that product.

9.3.4 Net Present Value for Various Price Forecasts

The profitability of the air-fired base case is measured using the NPV Method with three EIA energy price forecasts: low, reference, and high [24]. The NPV is computed using the hurdle rate to discount the cash flows. For the air-fired base case, Table 9-15 lists the NPV computed using the three EIA price forecasts for hurdle rates ranging from 0–14.1%. The IRR is 9.0% for the EIA reference forecast and 15.7% for the EIA high forecast. There is no IRR for the EIA low forecast as NPV < 0 at the 0% hurdle rate.

Any combination of price forecast/hurdle rate that has a negative NPV is not profitable as profits will be less than the specified hurdle rate. See Section 5.2.3 for details about the NPV Method.

Table 9-15. NPV of air-fired base case scenario (in billions of 2012 US$).

Hurdle	EIA Price Forecast		
Rate	Low	Reference	High
0.0%	$ (.90)	$ 1.91	$ 4.08
2.0%	$ (.93)	$ 1.21	$ 2.87
4.0%	$ (.95)	$ .71	$ 2.00
6.0%	$ (.96)	$ .36	$ 1.38
8.0%	$ (.95)	$ .10	$ .92
9.0%	$ (.95)	$ -	$ .74
10.0%	$ (.95)	$ (.09)	$ .58
12.0%	$ (.93)	$ (.23)	$ .32
15.7%	$ (.91)	$ (.40)	$ -

This in situ oil sands base case scenario is not profitable at any hurdle rate under the low energy price forecast. Since higher hurdle rates give larger discounts to cash flows each year, losses shrink as the hurdle rate increases, approaching a low price forecast limit of -$261 million as the hurdle rate goes to infinity.

Under the reference energy price forecast, NPV is positive for all values of hurdle rate less than or equal to the IRR of 9.0%. Under the high energy price forecast, the operation is profitable for all values of hurdle rate up to the IRR of 15.7%. The rates of return achievable under the reference forecast may not be commensurate with the riskiness of such a first-of-a-kind project and certainly do not reflect the geological uncertainty associated with finding a Uinta Basin oil sands deposit that meets the criteria for SAGD extraction. Also, the high degree of uncertainty in forecasting future oil prices (see Figure 5.3) makes it difficult to assess the rate of return that an investor might expect to receive.

9.3.5 Supply Price Sensitivity

Using the Supply Price Method, the sensitivity of the supply price of oil to the following parameters is investigated: drilling cost, overall SAGD cost, labor costs, cost for site preparation and service facilities, maintenance costs, fuel expenses (e.g. natural gas), and tax and royalty rates applied to the operation. For most of the parameters, high and low values relative to the base case are assumed and the resulting supply price is computed. Only low values relative to the base case are assumed for federal and state corporate income tax. Because drilling costs estimated from Connacher [10] are extremely low compared with drilling cost data obtained for wells drilled in the Uinta Basin (see Section 7.1.1.2), both parameter values tested are higher than the base case. Table 9-16 lists the supply price as a function of hurdle rate over the ranges of parameters tested.

Table 9-16. Sensitivity of supply price for in situ oil sands scenario to various parameters.

In Situ Oil Sand (Air-Fired)		Supply Price of Oil ($/bbl)			
		Hurdle Rate			
Variable	**Range**	**0%**	**4%**	**8%**	**12%**
Base Case	---	$ 83.93	$ 102.76	$ 127.70	$ 160.52
Drilling ($ / well)	**$ 384,000**				
Double	$ 768,000	$ 86.57	$ 105.92	$ 131.39	$ 164.94
In Situ Oil Shale Equivalent [a]	$ 3,000,000	$ 102.20	$ 124.29	$ 153.22	$ 190.65
SAGD - Capital & Op. Expenses	**100%**				
Low	50%	$ 62.83	$ 77.09	$ 95.97	$ 120.74
High	150%	$ 104.95	$ 128.28	$ 159.25	$ 200.08
Labor (# of operators / shift)	**62**				
Low	31	$ 78.01	$ 96.64	$ 121.40	$ 154.26
High	93	$ 89.86	$ 108.87	$ 134.00	$ 166.77
Site Prep. & Service Facilities (% of C_{TBM})	**16%**				
Low	10%	$ 81.74	$ 99.81	$ 123.75	$ 155.23
High	30%	$ 89.05	$ 109.63	$ 136.92	$ 172.84
Maintenance (% of C_{TDC})	**5%**				
Low	2%	$ 72.82	$ 91.29	$ 115.90	$ 148.78
High	8%	$ 95.05	$ 114.23	$ 139.52	$ 172.42
Fuel Costs	**100%**				
Low	50%	$ 75.79	$ 94.52	$ 119.38	$ 152.08
High	150%	$ 92.08	$ 111.00	$ 136.01	$ 168.95
Royalties (% of Sales) [b]	**8.0%-12.5%**				
Federal Land - standard fixed rate [c]	12.5%	$ 85.82	$ 105.50	$ 131.72	$ 166.05
Federal Land - oil shale rate [d]	5.0%-12.5%	$ 83.88	$ 102.61	$ 127.38	$ 160.09
Low [e]	5.0%	$ 79.31	$ 97.40	$ 121.48	$ 152.93
Federal Taxes (% of Taxable Income) [f]	**35%**				
Low [g]	15%	$ 79.45	$ 94.83	$ 115.32	$ 141.24
State Taxes (% of Taxable Income) [h]	**5%**				
SB65 Tax Credit [i]	< 2%	$ 83.24	$ 101.62	$ 126.03	$ 157.81
Combined	---				
All Unfavorable [j]	---	$ 166.74	$ 198.05	$ 238.63	$ 290.92
All Favorable [k]	---	$ 37.28	$ 47.47	$ 61.13	$ 78.51

[a] The base case drilling cost from the in situ oil shale scenario is used; this value is based on cost estimates from a variety of sources (see Section 7.1.1.2)
[b] Royalty rate for oil shale/oil sands leases on state (SITLA) lands; see Section 3.4.1.1
[c] Standard fixed rate for conventional oil lease
[d] Royalty rate given in 2008 royalty rules; see Section 3.4.1.1
[e] Lowest royalty rate proposed on either federal or state lands
[f] Federal corporate income tax rate based on taxable income
[g] Lowest federal corporate income tax rate
[h] Standard state corporate income tax
[i] State corporate income tax rate after state tax credit is applied; see Section 3.4.4
[j] All unfavorable = Uinta Basin well drilling costs, high SAGD costs, high labor costs, high site preparation and service facility costs, high maintenance costs, high fuel costs, 12.5% royalty rate
[k] All favorable = Base case drilling costs, low SAGD costs, low labor costs, low site preparation and service facility costs, low maintenance costs, low fuel costs, 5% royalty rate, federal income tax of 15%, state tax credit applies

Over the ranges of parameters tested, the cost of SAGD (including both capital and operating expenses) has the largest impact on supply price. This result is not surprising given the large percentage of overall capital and operating costs that is encompassed by the SAGD operation and the difficulty in disaggregating the SAGD data in order to provide a more specific analysis. An 50% increase or decrease in SAGD capital and operating expenses could represent a more continuous or discontinuous resource, a higher or lower frequency of beds with thickness exceeding 40 feet (12 meters), higher or lower overall bitumen recovery rates, more or less effective steam management, etc. Based on the average EIA reference price forecast of \$131.85/bbl (see Table 5-3), in situ oil sands production is profitable at all hurdle rates < 13.8% if SAGD costs are 50% of those scaled from Connacher [10,11]. Under the high oil price forecast (\$192.45), the operation is profitable for all hurdle rates < 20.7%. If SAGD costs are 150% of the scaled Connacher data, the operation is only profitable at very low hurdle rates (< 5.1%) assuming the average EIA reference price forecast; profitable hurdle rates increase to 11.9% assuming the high oil price forecast. As discussed in the introduction to Section 9, the oil sands resource in P.R. Spring (and in other STSAs in Utah) is too thin, too discontinuous, and too low of grade to be easily recoverable as it is in Canada. The low grade and thin pay zone mean that a large percentage of the thermal energy applied to the formation would go to heat the mineral content or would be lost to geological structures above and below the pay zone. Consequently, the high SAGD cost variation is more representative of what might optimistically be achieved in P.R. Spring or elsewhere in the Uinta Basin.

Drilling costs are included in the sensitivity analysis because of the very low per well cost (\$414,000) for the base case, which is based on an estimate from Grills [12] that 20% of a SAGD project's capital cost is for drilling. In Section 7.1.1.2, typical costs for drilling and completing a horizontal well in the Uinta Basin of the length needed for in situ thermal treatment ranged from \$2.0 million to \$6.5 million. For the in situ oil shale scenario, the base case drilling cost was assumed to be \$3.0 million. In this sensitivity analysis, one variation doubles the base case drilling cost while the other applies the \$3.0 million per well cost used in Section 7. Doubling the drilling cost has a very small effect on the supply price of oil; at a 0% hurdle rate, the price

Connacher may have used a higher per well cost in their analysis [10,11], but there is no way of knowing based on data available.

increases by \$2.64 while at a 12% hurdle rate, the price increase is \$4.42. Increasing the cost of drilling to \$3.0 million per well represents a seven-fold increase in cost over the base case with a commensurate impact on the supply price. At a 0% hurdle rate, the supply price increases by \$18.27 and at a 12% hurdle rate, the supply price increases by \$30.13 over the base case. In terms of profitability, the base case is profitable up to a 9.0% hurdle rate under the average EIA reference oil price forecast while the highest drilling costs (\$3.0 million) reduce the profitable hurdle rate to only 5.7% (or 12.8% under the high oil price forecast).

Labor estimates for the base case were determined following the approach of Seider et al. [13]. However, based on scaled data from Connacher [10], the number of operators per shift for the SAGD part of the operation was lower than the base case estimate by 30%. The sensitivity of the supply price to a ± 50% change in the number of operators required per shift is shown in Table 9-16. The supply price at all hurdle rates increases or decreases by approximately \$6/bbl.

Site preparation and service facilities costs cover the miscellaneous expenses associated with development of the production site as outlined in Seider's methodology [13]. These costs could reflect, among other things, the amount of pre-existing development at the site and the difficulty in developing the site due to distance from other infrastructure. Recommended site preparation costs range from 4–20% of C_{TBM} and service facilities costs from 5–20% of C_{TBM}. The selection of these percentages is somewhat arbitrary but results in changes to capital expenses on the order of tens up to hundreds of millions of dollars. For this scenario, the base case percentage was 16% (8% each) rather than the 20% (10% each) used in the other scenarios. This lower value was selected to avoid duplication of costs as some of the components included in Connacher's capital cost estimate are also included in this capital cost category; see Section 9.1.1.4. The low percentages in the sensitivity analysis (5% each) are typical for making an addition to an integrated complex, while the high percentages (15% each) are in the mid-range of costs for green sites. Over this range of capital costs, the supply price changes by \$2–\$12/bbl depending on hurdle rate. Higher hurdle rates are affected more strongly because discounts to cash flow in later years of the project weight cash flows in earlier years of the project more heavily.

Maintenance costs are estimated as a percentage of C_{TDC}, with recommended values ranging from 2% [22] to 11.5% [35]. For the air-fired case, C_{TDC} is \$881 million and annual maintenance costs are on the order of tens of millions of dollars. Thus, the choice of maintenance percentage has a significant impact on the supply price; an increase or decrease in the base case value of 5% by three percentage points results in an \$11–\$12/bbl change in the supply price of oil.

Fuel (e.g. natural gas) is the only significant "utilities" contributor to the supply price. Altering the fuel costs ± 50% moves the supply price by \$8/bbl, demonstrating the impact of changes in fuel purchase price or fuel utilization. The overall natural gas consumption reflected in the base case value has been reduced by accounting for the heating value of both produced gas from SAGD wells and waste fuel gases from the delayed coker, which supply 28% of the total required heating.

Fuel costs are one order of magnitude larger than electricity costs and two orders of magnitude larger than water costs. Steam costs for SAGD and for other processing steps are included in the SAGD capital and operating expenses.

Also in Table 9-16 is the supply price for oil assuming a range of royalty and tax rates/credits that federal and state governments have suggested for oil sands and/or conventional oil development. The impact of these policies increases with hurdle rate. At a hurdle rate of 12%, a fixed royalty rate of 5% reduces the supply price of oil by $7.59 over the base case while a fixed royalty rate of 12.5% raises the supply price of oil by $5.53. Reducing the federal corporate income tax rate from 35% to 15% reduces the supply price of oil by $19.28 while applying the Utah state tax credit decreases the supply price by $2.71.

Finally, the combined effect on the supply price of applying all the favorable and unfavorable parameters in Table 9-16 is given as a function of hurdle rate. These "All Favorable" and "All Unfavorable" prices provide outer bounds on the supply price range for this scenario, assuming that a suitable resource could be found.

9.3.6 Analysis and Summary

This section examines the supply costs and prices for this scenario in the context of published information about commercial-scale oil sands development in Canada. Based on results from the sensitivity analysis in the previous section and assuming that oil prices remain at levels predicted in either the EIA reference or high price forecasts for WTI-quality oil, this scenario exhibits economic viability over some of the parameter space that is examined. However, the question of whether oil sands deposits exist in Utah that could be successfully exploited with SAGD technology remains unanswered and introduces a large degree of uncertainty in the reported numbers.

Projected supply costs for Canadian oil sands operations were published in a 2012 CERI report [36] for a project timeline extending from 2011–2045. As noted in Section 8, CERI uses a methodology that is essentially the same as the Supply Price Method in this report. That is, they fix a hurdle rate (10%) and compute the constant price needed to attain a project ROR/IRR equal to that rate. The report gives both supply costs at the "plant gate" (transportation and blending costs are excluded) and "WTI-equivalent" supply costs (adjusting for blending and transportation costs for blended bitumen) for a SAGD operation but not for an integrated SAGD/upgrading facility. In their model, the authors assume that the SAGD operation has a 30,000 BPD production capacity, a production life of 30 years, and a capacity factor of 75%. The "plant gate" supply cost is $46.91. In this report (10,000 BPD operation), the "plant gate" supply cost (10% hurdle rate) from Table 9-14 is $84.00, which is 79% greater than the CERI supply cost.

All numbers from the CERI report (2010 C$) have been adjusted to 2012 US$ assuming a 1:1 C$/US$ exchange rate and are adjusted for inflation using the CEPCI index.

The hurdle rate is the minimum expected rate of return a project needs to attain in order to be considered profitable. The ROR may be more or less than the hurdle rate because it depends on the actual paths of prices and costs.

The "WTI-equivalent" prices from CERI and from this report are not compared because the products are not the same (blended bitumen and upgraded SCO, respectively).

A supply cost breakdown comparing CERI costs with this report's bitumen production costs is shown in Table 9-17. In comparing results from the two reports, three issues must be considered. One, while CERI references the Connacher data for its SAGD costs, some of the its base case inputs do not match up with the Connacher inputs. Two, this report uses Williams' six-tenths rule [37], as summarized in Section 5.4.1, to scale the Connacher data from a 24,000 BPD operation to a 10,000 BPD operation. It is not clear exactly how the Connacher data is used in the CERI report. Three, the way costs are aggregated and the scales of the operations are different in the two reports.

Comparing table entries, the total U.S. tax burden exceeds the Canadian tax burden by a factor of six. As outlined in Table 3-3, the Canadian federal income tax is 16.5% compared to 35% in the U.S and the provincial tax in Alberta is 10% while the Utah state tax is 5%. There are other taxes that apply as well, but CERI does not provide a detailed breakdown of the tax burden. Next, the cost differential for natural gas is driven by two factors: the assumed natural gas input and the forecast price. In this report, the fuel requirement for producing bitumen, as scaled from Connacher data, is 1.50 GJ/bbl. The CERI report lists as an input a fuel requirement of 1.07 GJ/bbl. With respect to natural gas price, this report's Supply Price Method analysis assumes a fixed price for natural gas as shown in Table 5-7. The CERI report uses the EIA forecast price for natural gas and then applies a differential to "better reflect the actual cost paid by producers for natural gas." Finally, there is a large difference in the cost of fixed capital. The application of scaling laws to account for the differences in production level contribute to this difference but do not fully explain the doubling of this cost category in the present analysis.

"Plant gate" refers to the bitumen-only production cost and does not include blending, transportation, or upgrading costs.

Table 9-17. "Plant gate" supply cost breakdown for a SAGD operation (10% hurdle rate); data from Millington et al. [36]) and from the Supply Price Method analysis in this report (see Table 9-10).

Cost Category	CERI Plant gate, 30,00 BPD ($/bbl)	Supply Price Method Plant gate, air-fired, 10,00 BPD ($/bbl)
Emissions compliance costs[a]	$0.63	$0.12
Income taxes[b]	$2.95	$18.45
Royalties	$8.88	$8.98
Abandonment costs	$0.02	- - -
Other operating costs (fixed & variable)[c]	$11.69	$8.68
Fuel (natural gas)	$4.59	$9.63
Operating working capital[d]	$0.42	- - -
Fixed capital (initial, sustaining, & ROR)[e]	$17.73	$38.14
Total supply cost	**$46.91**	**$84.00**

[a] *Permitting*

[b] *State and federal income taxes, property taxes, and severance taxes*

[c] *All costs not explicitly included in other categories (electricity, catalysts, research, administration, incentive compensation, mining, solvent, refrigerant, steam, water, labor, overhead, insurance, and intellectual property royalties)*

[d] *Working capital is counted as a cost at the beginning of the project and income at the end, so it has no cost unless costs are presented in terms of present value*

[e] *All capital costs included in C_{TDC}, land, startup, and maintenance; also includes ROR or "net earnings"*

The fuel higher heating value is used as the basis for all energy inputs and outputs.

An EROI for the base case in situ oil sands production scenario has been estimated by dividing the energy outputs (SCO and coke) by the energy inputs.The inputs include the electricity and natural gas use for each of the processes described in this section and the energy required for drilling, steam generation, water delivery, and O_2 production. They do not include the energy required for facilities construction, water treatment or refrigeration. The EROI of both the air- and oxy-fired base case scenarios is 2.21. Additional details about these EROI numbers are found in Kelly et al. [40].

In a summary of EROI values for various fuels, Murphy and Hall [38] list an EROI of 2–4 for bitumen (not SCO) from tar sands. In another publication by Murphy and Hall [39], they tabulate estimates of EROI for oil sand production. The EROI range in their table is 1–7.2, although it is not clear whether the EROI is for ex situ or in situ production, if the energy input associated with upgrading is included, and if the energy output is bitumen or SCO.

This analysis provides an overview of the factors that impact profitability of an in situ oil sands development in the Uinta Basin. These results assume that a suitable resource has been found when in fact no such resource has yet been identified. Given the uncertainty of resource availability, great caution should be used in applying the numbers presented herein.

9.4 References

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10 Estimated Economic Impacts of the Ex Situ Oil Shale and Ex Situ Oil Sands Scenarios

10 Estimated Economic Impacts of the Ex Situ Oil Shale and Ex Situ Oil Sands Scenarios

The previous four sections provided a microeconomic or profitability analysis of various unconventional fuel development scenarios in Utah's Uinta Basin. In this section, the focus is on the broad regional impacts that may result as side effects if the scenarios were realized. An analysis of these effects, also called a "macroeconomic" or "economic impact" analysis, indicates the impact of private investment of this magnitude on the regional economy.

This section reports results from an input-output (IO) analysis of the potential economic impacts arising from successful oil shale or oil sands projects in the Uinta Basin. Two particular projects are analyzed: the 50,000 BPD ex situ oil shale scenario described in Section 6 and the 10,000 BPD ex situ oil sands scenario described in Section 8. Impacts are evaluated from the point of view of two regions: the State of Utah as a whole and the Uinta Basin, defined as Utah's Duchesne and Uintah counties collectively. Further, impacts associated with a project's relatively short-lived construction phase are estimated separately from those of its operations phase. Estimates are thus reported for eight project-region-phase combinations.

The estimates reported in this section are those of a successful industry. The commercial prospects of the oil shale and oil sands scenarios of this section are analyzed in Sections 6 and 8 respectively and are not further considered in the present section. This qualifier (commercial viability) is of particular importance because economic impacts to a given region as modeled in traditional IO analyses are based on project expenditures in that region. The full economic impact of a project will only be attained if the project is commercially successful. Impact estimates for projects unlikely to realize commercial success are as speculative as the project itself.

A traditional IO analysis of economic impacts, such as the one presented in this section, is not a benefit-cost analysis. For the purpose of public policy discussions, it is therefore appropriate only as part of a more comprehensive consideration of the benefits and costs of unconventional fossil fuel development. Apart from the limited scope of economic impact analysis for public decision-making, it has to be noted that seemingly considerable, but not readily quantified, uncertainty accompanies traditional economic impact estimates. This issue is further discussed below.

10.1 Economic Background

The scenarios analyzed in this report are located in areas historically and presently very active in the production of conventional oil and natural gas. Table 10-1 shows average daily oil production for the five highest-producing Utah counties during 2011. Of the nearly 72,000 BPD produced statewide, almost 52,000 BPD—more than two out of every three barrels—were produced in the Uinta Basin. Thus, the ex situ oil shale scenario, at 50,000 BPD, nearly equals recent total oil production in the Uinta Basin. The 10,000 BPD ex situ oil sands scenario exceeds recent rates of oil production in Sevier County and almost equals the current rate of production in San Juan County.

The Uinta Basin is defined as Duchesne and Uintah Counties combined.

Table 10-1. Recent and cumulative oil production in Utah's top oil-producing counties [1].

County	2011 Production (BPD)	Share	Cumulative (Barrels)	Share
Duchesne	32,691	45%	354,576,485	25%
Uintah	19,171	27%	274,708,022	19%
San Juan	11,579	16%	568,174,692	40%
Sevier	6,909	10%	15,804,985	11%
State Total	**71,981**		**1,433,126,386**	

Not surprisingly, employment in the Uinta Basin is also much more concentrated in the oil (and natural gas) industry than is the state as a whole. For the purpose of this section, the "oil and gas industry" consists of the combined "oil and gas extraction" (NAICS 211) and "support activities for mining" (NAICS 213) industries. The "support activities for mining" industry does, however, include support activities for mining other than for oil and gas.

NAICS is the North American Industry Classification System.

In 2011, the estimated population of the Uinta Basin was 52,000 persons, with Duchesne County having 19,000 and Uintah County having 33,000. Statewide population equalled about 2.8 million persons in 2011 [2]. Duchesne and Uintah Counties employed an average of 8,000 and 13,000 persons, with total payrolls of $315 million and $546 million respectively.

Statewide, oil and gas industry wages are about double the average wages. In 2011, an average of 7,000 of the 1.2 million persons employed in Utah (approximately 0.5%) were employed by the oil and gas industry. The statewide oil and gas industry payroll equaled $509 million of the total statewide payroll of $45 million (approximately 1%). As noted above, these figures include activities in support of other types of mining than oil and gas.

Other types of mining in the state include coal and hard rock.

Table 10-2 shows total and mining industry employment statewide and in the counties of the Uinta Basin. Total wages paid in the Basin (private and public) equalled almost $1 billion in 2011 ($48 billion statewide). The oil and gas industry and supporting services had a 2011 Uinta Basin payroll of approximately $350 million ($854 million statewide).

Table 10-2 also shows further detail on statewide and Basin employment. In 2011, the oil and gas industry employed about 1,800 persons in Duchesne County with total payroll of $124 million and 3,100 persons in Uintah County with total payroll of $226 million. Since total employment is 8,000 and 14,000 persons respectively, about 22% of those employed in either Duchesne or Uintah County are employed in the conventional oil and gas industry. The average annual wage in the oil and gas industry is approximately $72,000 in either county and about twice the average annual wage of jobs outside of the oil and gas industry. Thus, in either county, wages paid by the oil and gas industry comprise about 65% of total wages.

Table 10-2. Mining industry (including oil and gas) employment in 2011 [3].

Industry	Region	Average Employment	Payroll (Millions of 2011 US$)	Average Monthly Wage (2011 US$)
Oil and Gas Extraction	State	1,590	151.8	7,954
Mining (except Oil and Gas)	State	5,019	345.1	5,730
Support Activities for Mining	State	5,054	356.9	5,885
All Private	State	988,039	39,075.1	3,296
All	State	1,208,815	47,916.3	3,303
Oil and Gas Extraction	Basin	1,207	107.3	7,406
Mining (except Oil and Gas)	Basin	324	24.5	6,302
Support Activities for Mining	Basin	3,325	218.1	5,465
All Private	Basin	17,371	826.4	3,965
All	Basin	22,210	988.2	3,708
Oil and Gas Extraction	Duchesne	735	62.8	7,127
Mining (except Oil and Gas)	Duchesne	10	0.3	2,648
Support Activities for Mining	Duchesne	1,021	60.9	4,969
All Private	Duchesne	6,034	286.7	3,960
All	Duchesne	8,016	346.2	3,599
Oil and Gas Extraction	Uintah	472	44.4	7,851
Mining (except Oil and Gas)	Uintah	314	24.5	6,497
Support Activities for Mining	Uintah	2,304	157.1	5,685
All Private	Uintah	11,337	539.8	3,968
All	Uintah	14,194	642.0	3,769

Note that, unlike the state as a whole, the "Mining (except oil and gas)" (NAICS 212) industry has a small share in the "Mining" industry (NAICS 211, 212, and 213 combined) in the Uinta Basin. Statewide, the "Mining (except for oil and gas)" industry accounts for almost half of the employment and wages in the "Mining" industry. In the Uinta Basin, however, the "Mining (except oil and gas)" industry accounts for only about 8% of "Mining" employment and wages. This difference reflects the fact that although coal and copper mining are significant industries statewide, neither resource is mined in the Basin.

10.2 Economic Impacts Methodology

The economic impacts reported in this section are based on IO analysis. Though a standard tool for estimating economic impacts, it is important to understand the main assumptions of IO analysis and the limitations they entail for its use in public policy evaluation. A brief discussion of IO analysis follows.

A series of papers [4,5] authored by researchers associated with Cornell University critically assess the scope and reliability of IO analysis in general and as it has been applied to the estimation of economic impacts due to the Pennsylvania Marcellus shale gas development. Some of the limitations of IO analysis are suggested in the present section, but the reader is referred to those papers for a comprehensive discussion.

10.2.1 Output Impacts Example

An IO table shows the total flow of the monetary value of goods and services between sectors of the economy over a fixed period of time, usually a year. The number of sectors represented can vary from just a few to about 500, limited only by the availability of data. For instance, the models used for the analysis presented in this section represent 60 sectors, including "Oil and Gas Extraction," "Construction," "Machinery Manufacturing," and "Professional, scientific, and technical services." Flows between sectors arise out of supply-demand interdependence among sectors. For example, when a company receives an increase in orders for its products, it will generally need to increase production. When it does this, it will need to purchase more of the labor and materials it uses in production. Increased production in these sectors, in turn, gives rise to an increase in production to their suppliers, and so on—a chain reaction of effects working through the inter-industry linkages.

However, linkages between sectors are model constructs rather than "plain facts." In IO analysis, the flow of dollars from a purchasing sector to a supplying sector is modeled as a constant proportion of the output (as measured in dollars) of the purchasing sector. For example, according to the 2002 U.S. Benchmark Input-Output Accounts, the "Mining" sector purchased in that year $5.5 billion of output from the "Utilities" sector [6]. In the same year, the Mining sector produced a total of $170 billion in output (the sum of the value of all mining products in 2002). Applying the "constant proportions" assumption to the IO table, the flow from the Mining sector to the Utilities sector takes place at the constant rate of $0.03 per $1 of Mining output.

One of the "first-round" effects of a $1 million increase in Mining output is, according to the data given and "constant proportions," to increase the output of the Utilities sector by $30,000. Other first-round effects arise from the other direct suppliers of the Mining sector. For instance, Mining also purchased $8.6 billion from the Mining sector in 2002, so that the first-round effect of $1 million of Mining output is an additional $32,000 of Mining output, a rate of $0.032 per $1 of Mining output. There are as many first-round effects as there are sectors represented.

Second-round effects arise in exactly the same way as the first-round effects: Each industry experiencing an increase in output due to the first-round responds by "pulling" on the industries that are its direct suppliers. The second-round effects give rise to third-round effects and so on. Conceptually, there is no final round, but in usual cases the size of the subsequent-round effects decrease fast enough that the sum effect of all rounds converges to a number. That number, the "business sales" (or "output") impact, is one of the main economic impacts reported in this section.

The "business sales," or "output" impact of an economic stimulus is the sum of all the business-to-business sales that result, directly and indirectly, from the stimulus.

The ratio of the impact and the original expenditure that gives rise to it is called a "multiplier." Thus the impact is the product of the original expenditure and the multiplier. The results presented below for the oil shale and oil sands scenarios are based on multipliers estimated by the U.S. Department of Commerce, Bureau of Economic Analysis.

An example is now presented which, though simplified in a number of ways, captures the essential parts of IO methods leading to the calculation of impact multipliers. Consider an economy with two sectors, Mining and Utilities. The U.S. Benchmark Accounts show that the Utilities sector, with $387 billion of total output, purchased $62 billion of output from the Mining industry and $0.377 billion from the Utilities sector [6]. Including the purchases made by the Mining sector noted above, this partial IO table looks like Table 10-3.

Mining purchases include coal and natural gas.

Table 10-3. Illustrative IO relations, taken from the 2002 U.S. Benchmark Accounts [6]. All numbers are given in billions of US$.

In this table, the purchasing sectors are the column sectors and the selling sectors are the row sectors.

	Mining	Utilities
Mining	$8.60	$62
Utilities	$5.50	$0.377

Taking the IO table and dividing each row by the output of the corresponding sector yields Table 10-4—called the "direct requirements table" or "D"—of the constant proportions discussed above.

Table 10-4. Direct requirements table for two-sector economy.

	Mining	Utilities
Mining	0.051	0.160
Utilities	0.032	0.001

Figure 10.1 shows these relations graphically. The arrows are in the direction of the flow of money (i.e. from the purchasing sector, to the selling sector). Suppose there is an exogenous increase in demand leading to increased sales for the output of the Utilities sector. IO analysis essentially comes down to this question: What is the total flow of funds through the economy, as depicted here, induced by such an increase of sales?

An exogenous increase in demand arises from a source external to the economic system under consideration.

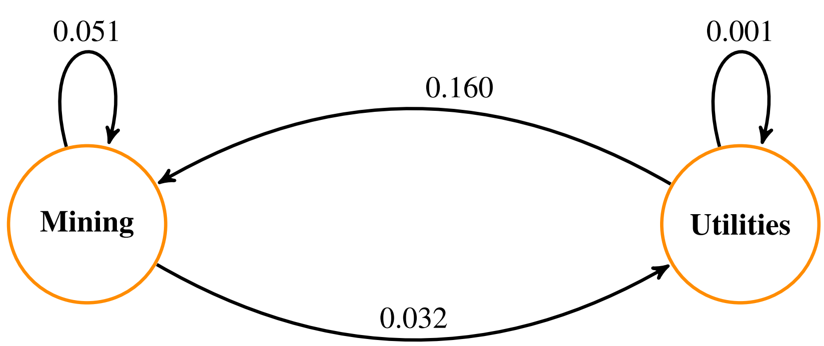

Figure 10.1: Graphical depiction of the direct requirements table, D.

The first round impact of a 1-unit (e.g. $1 million) change in expenditure can then be computed by applying matrix multiplication methodologies [7]. Second-round up to k^{th} round effects are computed using the result from the previous round as the starting point for the next round. Assuming sensible values for the constant proportions, it has been shown by Waugh [7] that the total effect of all the rounds converges to a single number for each sector as shown in Table 10-5 for this simple example. In Table 10-5, an initial expenditure of $1 million in the Utilities sector gives rise to a total economic output of $1,176,311—the initiating $1 million plus $6,475 from the Utilities sector and $169,836 from the Mining Sector.

Table 10-5. Total requirements table for two-sector economy.

	Round 0	Round 1	Round 2	Round 3	...	Total
Mining	$0	$160,207	$8,261	$1,248	...	$169,836
Utilities	$1,000,000	$974	$5,184	$272	...	$1,006,475

The ratio of that part of the total output beyond the initiating expenditure (in this example, $176,311) to the initiating expenditure (in this example, $1,000,000) is called the "output multiplier" for the particular industry receiving the initial expenditure (in this example, the Utilities sector). As shown in Equation (10.1), the output multiplier for Utilities is 0.176. That is, one unit of expenditure in the Mining sector gives rise to 0.176 additional units of expenditure in the economy. The output multiplier for the Mining sector can be computed similarly; it is 0.093. In this simplified example, the Utilities multiplier is larger, owing to the strong dependence of the Utilities sector on the output of the Mining sector. Both multipliers are, however, quite small compared to those computed from full IO tables. The multipliers used in this study generally vary between one and three.

The multipliers (output, labor, etc.) used in this report are "additional effect" multipliers, meaning they are net of the initiating expenditure as shown in the illustration.

$$\frac{(1{,}006{,}475 + 169{,}836 - 1{,}000{,}000)}{1{,}000{,}000} = 0.176 \qquad \textbf{(10.1)}$$

Some IO tables, such as the 60-sector versions used for the present study, incorporate households as a sector. In this framework, consumption of goods and services from other sectors is the "input" to the household sector and labor performed for a particular sector is the "output." Incorporating households is as straightforward as adding an additional row and column to the IO table. To make a final extension of this example, and again referring to the U.S. Benchmark Accounts for 2002 [6], the Mining and Utilities sectors paid $29 billion and $57 billion respectively in employee compensation. The IO table shown in Table 10-6 is identical to Table 10-3 in the first two rows and columns. The last row shows sales of labor to the Mining and Utilities sectors; the last column shows purchases made by the Household sector from the Mining and Utilities sectors.

Table 10-6. Illustrative IO relations, including Households, taken from the 2002 U.S. Benchmark Accounts [6].

	Mining	Utilities	Households
Mining	$8.60	$62	$0.10
Utilities	$5.50	$0.40	$216
Households	$29	$57	$0

The direct requirements table, D, is similarly extended as shown in Table 10-7. These relations are depicted graphically in Figure 10.2.

Table 10-7. Direct requirements table for three-sector economy.

	Mining	Utilities	Households
Mining	0.051	0.160	0.00
Utilities	0.032	0.001	0.04
Households	0.17	0.15	0.00

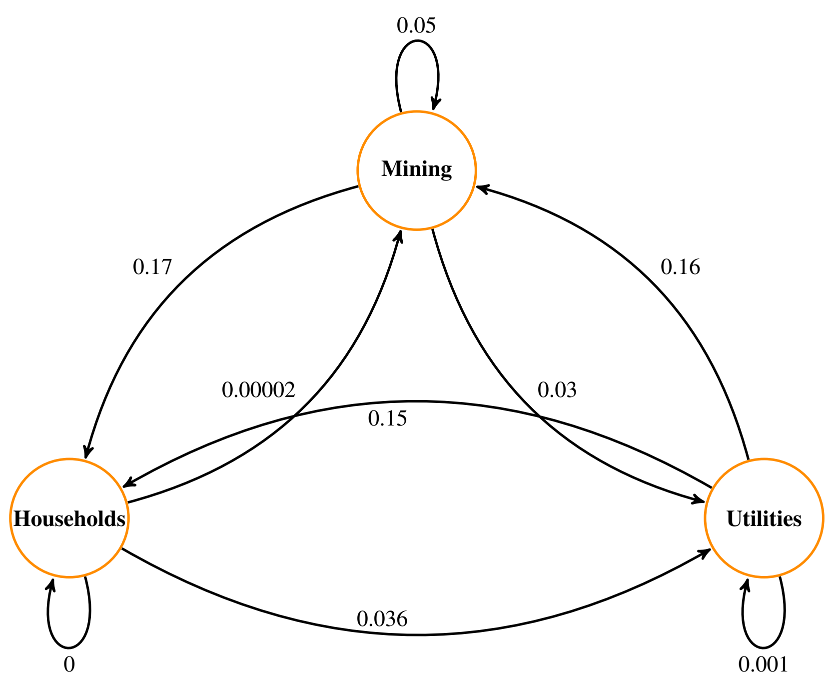

Figure 10.2: Graphical depiction of the direct requirements table, D.

The total requirements tables and the (additional) output multipliers can then be computed. With the inclusion of the Household sector, the multiplier for the Utilities sector increases to 0.36 from its previous value of 0.176. Similarly, the Mining Sector multiplier increases to 0.29 from its previous value of 0.093.

Using these multipliers, a $1 million exogenous increase in the output of the Utilities sector would be predicted to lead to an additional change in system-wide output of about $360,000. Though highly simplified in a number of respects, the foregoing discussion and examples illustrate the key features of IO analysis.

10.2.2 Other Impacts

Given the output impacts and some readily available additional data, other sorts of impacts can be derived. Apart from the output (business sales) impact, those that are reported in this section include the wage earnings, employment (jobs), and value-added (GSP) impacts.

GSP refers to gross state product.

The earnings impact measures the total increase in household earnings due to an increase in the output of a given sector. Corresponding to the earnings impact is the "earnings multiplier," which is the ratio of the change in total earnings (among all sectors) to the change in output in the given sector. Referring back to the graph in Figure 10.2, the total change in earnings is the total flow through the Household sector due to a stimulus in some given sector (e.g. due to an increase in Mining output).

Household earnings are defined as the sales of labor by households to each of the other economic sectors.

Estimates of the employment impacts for a given sector are obtained by multiplying the earnings impact in that sector by the average number of jobs per unit of earnings in that sector. Job impacts are reported in job-years.

The value-added impact can be thought of as the net output impact. Rather than adding up the full value of all production, the value-added measure subtracts the value of all the inputs to each particular output. As a measure, it is almost identical to gross national (or state) product.

10.2.3 Economic Impact Estimates

The economic impacts reported in this section are based on Utah statewide or Uinta Basin economies. As discussed above, the impetus of the impacts is an exogenous event that calls for increased output from one or more industries. For example, out-of-state orders for electricity produced in Utah lead to funds flowing into the state from another state. In the so-called "economic base" framework of economic impacts, the almost universal framework in IO economic impact studies, demands originating from within the region of interest typically do not generate economic impacts. This is because the funds that initiate the increased activity are funds that cannot also be spent within the region on other activities. Thus, the increase in the activity of the stimulated industry is offset by the decline in the activity of the industries from which the funds are withdrawn.

The impacts reported for the oil shale and oil sands scenarios assume that the projects are financed from sources external to the state (in the statewide case) or the Basin (in the Uinta Basin case) and that the oil produced is either sold to buyers external to these regions or prevents the need for oil to be imported from outside the regions (replacing oil imports from Canada, for example).

To the extent that the oil produced from the oil shale or oil sands development scenarios decreases production of oil in the state that would have been produced in the absence of oil shale/sands production, the economic impacts of this scenario are reduced from what is reported below. For example, increased oil production increases the demand for oil transportation and may increase the price of transportation per barrel of oil. Any potential oil projects that would be barely viable with the usual transportation costs would not go forward under the increased costs. Regional bottlenecks in transportation are one way for regional oil prices to diverge from their more usual relation to some benchmark price. The impacts reported in this section implicitly assume that transportation constraints are not binding.

For this analysis, the price of oil is assumed to be exogenous rather than depending on the balance of supply and demand in the Uinta Basin.

ln a regional economy such as the Uinta Basin or the State of Utah, funds flow into the region, circulate within the region, and exit the region to enter and circulate within another region. Funds that leave a region are called "leakages"; the higher the rate of leakages, the smaller the total regional impact of a given stimulus. The rate of leakage from a regional economy depends on the particular structure of the inter-industry linkages. Generally, however, regions that are larger economically have lower rates of leakage. In a small region such as the Uinta Basin, leakages from the Basin into neighboring counties, the rest of the state, or into other states or even countries will typically occur at a faster rate than funds circulating statewide. Estimates of the leakage rate are built into the multipliers used in this section. The multipliers for the Uinta Basin, for example, are considerably smaller than the statewide multiplier of the same sector.

Some of the shortcomings of IO analysis as a tool for policy evaluation have been suggested in the foregoing discussion. Concerning scope, IO analysis, as traditionally carried out, does not include an assessment of externalities. Generally, what economists refer to as "opportunity costs" are in effect assumed to be zero. For example, it is implicitly assumed in traditional IO analysis of impacts that labor and capital markets are "slack" in the sense that labor and capital utilized in the given project would not have been employed otherwise.

It is possible to evaluate certain environmental impacts in an IO framework as shown in a recent report by Headwaters Economics [8].

To evaluate a project solely on the results of traditional IO analysis of impacts is to evaluate a project's benefits but not its broader costs, leaving the result of such evaluations a foregone conclusion. If it is believed that a given project entails significant externality or opportunity costs, then those costs should be evaluated separately. For example, the empirical relationship between energy development and regional growth is more ambiguous than suggested by the assumption of zero opportunity costs [9,10].

10.3 Construction Impacts

The following subsections give the economic impacts of the construction phase as measured by the RIMS II 60-sector IO model of Utah and the Uinta Basin, developed by the U.S. Department of Commerce, Bureau of Economic Analysis. The three-year construction period is assumed to follow a one-year design period for a total of four years for the construction phase of the ex situ oil shale and oil sands scenarios analyzed in this section; see Section 5.2 for a project schedule.

10.3.1 Ex Situ Oil Shale

Tables 10-8 and 10-10 report the economic impacts to the State of Utah of the Tosco II and Paraho Direct ex situ oil shale scenarios, respectively, during their construction phase while Tables 10-9 and 10-11 report the economic impacts to the Uinta Basin. All tables show the industries which are assumed to receive the original stimulus from the project during the construction phase ("Industry"), the part of the total expenditure assumed to be spent on suppliers within the region ("Regional Share"), and the estimated business sales ("Sales"), wage earnings ("Wage Earnings"), and employment impacts ("Job-Years") of these regional expenditures. Tables 10-8 and 10-10 also include the value-added impact to the state ("GSP").

Table 10-8. State of Utah economic impacts attributed to the construction phase of the Tosco II ex situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	GSP
Machinery Manufacturing	1,705.6	3,698.6	878.7	20,623	1,638.9
Mining, except oil and gas	493.0	982.2	209.6	4,749	520.4
Support Activities for Mining	339.9	793.2	250.0	6,685	415.8
Construction	219.8	528.8	125.7	2,818	238.6
Professional, scientific, and technical services	88.5	195.7	73.4	1,783	121.8
Households	64.8	90.0	25.0	802	51.9
Utilities	58.8	104.0	20.1	386	59.6
Total	**2,970.4**	**6,392.5**	**1,582.6**	**37,844**	**3,047.1**

Table 10-9. Uinta Basin economic impacts attributed to the construction phase of the Tosco II ex-situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years
Machinery Manufacturing	1,125.7	1,570.9	455.7	9,411
Mining, except oil and gas	325.4	518.6	142.9	2,585
Support Activities for Mining	224.3	355.1	127.6	3,066
Construction	145.1	195.7	43.2	860
Professional, scientific, and technical services	58.4	86.7	32.4	671
Households	42.8	28.9	8.4	273
Utilities	38.8	53.3	9.6	140
Total	**1,960.5**	**2,809.3**	**819.7**	**17,005**

Table 10-10. State of Utah economic impacts attributed to the construction phase of the Paraho Direct ex situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	GSP
Machinery Manufacturing	1,155.7	2,506.1	595.4	13,973	1,110.5
Mining, except oil and gas	584.1	1,163.8	248.3	5,627	616.6
Support Activities for Mining	281.3	656.5	206.9	5,533	344.2
Construction	174.0	418.5	99.5	2,230	188.8
Professional, scientific, and technical services	76.1	168.2	63.1	1,532	104.7
Households	71.3	126.1	24.4	467	72.3
Utilities	52.1	72.4	20.1	645	41.7
Total	**2,394.6**	**5,111.6**	**1,257.8**	**30,008**	**2,478.8**

Table 10-11. Uinta Basin economic impacts attributed to the construction phase of the Parahp Direct ex-situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years
Machinery Manufacturing	762.7	1064.4	308.8	6,376
Mining, except oil and gas	385.5	614.4	169.3	3,063
Support Activities for Mining	185.7	293.9	105.6	2,537
Construction	114.8	154.9	34.2	681
Professional, scientific, and technical services	50.2	74.6	27.9	577
Households	47.0	64.6	11.7	170
Utilities	34.4	23.2	6.7	219
Total	**1,580.4**	**2,290.1**	**664.0**	**13,623**

Tables 10-8 and 10-10 differ from Tables 10-9 and 10-11 in both the impact multipliers and the "Regional Share." For the purpose of this case study, one-third of total expenditures are expected to be spent in the Uinta Basin, while one-half are expected to be spent somewhere in the State of Utah. As there is no historical data on purchases, these fractions are simply assumed. If the actual amount is higher or lower by some factor, the estimated impacts are increased or reduced by the same factor because of the linearity of the IO model. For example, if the actual regional share of expenditures turns out to be half of what is assumed here, then all the impacts to that region will also be reduced by half.

For the Tosco II ex situ oil shale scenario (air-fired), total permanent investment (C_{TPI}) is \$5.94 billion; see Table 6-8. When the region is "Utah," the regional share of this total expenditure is \$2.97 billion (50%). When the region is the "Uinta Basin," the regional share is \$1.96 billion (33%). Based on the data in Table 10-8, the \$2.97 billion assumed spent on Utah-based suppliers is shown to generate an additional \$6.40 billion in business sales, \$1.58 billion of wage earnings associated with about 38,000 person-years of employment, and about \$3.05 billion of GSP in Utah. Based on the data in Table 10-9, the \$1.96 billion assumed to be spent on suppliers located in the Basin is shown to generate an additional \$2.81 billion in business sales and \$0.82 billion of wage earnings associated with about 17,000 person-years of employment.

For the Paraho Direct ex situ oil shale scenario, C_{TPI} is \$4.79 billion; see Table 6-8. The "Utah" regional share of this total expenditure is \$2.40 billion (50%) and the "Uinta Basin" regional share is \$1.58 billion (33%). The \$2.40 billion assumed spent on Utah-based suppliers generates an additional \$5.11 billion in business sales, \$1.26 billion of wage earnings associated with about 30,000 person-years of employment, and about \$2.48 billion of GSP for the state; see Table 10-10. The \$1.58 billion assumed to be spent on Uinta Basin suppliers generates an additional \$2.29 billion in business sales and \$0.66 billion of wage earnings associated with about 14,000 person-years of employment (see Table 10-11).

The differences in the impacts to Utah and the impacts to the Basin reflect not just the different regional shares of expenditures but also some aspects of the regional economic structure. Expenditures in the Basin are 67% of statewide expenditures, but the impacts to the Uinta Basin are not 67% of statewide impacts. Rather, they vary between one-third and one-half of the impacts statewide. The key regional economic feature that determines the impacts of a given expenditure is the extent to which the linkages between suppliers and purchasers are internal to the region. In the present case, a given expenditure "leaks" out of the Basin economy at a faster rate than the statewide economy.

A statewide economy naturally internalizes links to a greater degree than any county it contains.

10.3.2 Ex Situ Oil Sands

The C_{TPI} during the construction period for the oil sands scenario is \$818 million; see Table 8-9. When the region is "Utah," the regional share of this total expenditure is \$412 million (50% of C_{TPI}). When the region is the "Uinta Basin," the regional share is \$272 million (33% of C_{TPI}).

Table 10-12 reports the economic impacts to the State of Utah of the ex situ oil sands scenario during its construction phase. The \$412 million assumed spent on Utah-based suppliers is shown to generate in the state an additional \$875 million in business sales, \$217 million of wage earnings associated with approximately 5,200 person-years of employment, and about \$433 million of GSP.

Table 10-12. State of Utah economic impacts attributed to the construction phase of the ex situ oil sands scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	Value-Added
Machinery Manufacturing	158.3	343.3	81.6	1,914	152.1
Mining, except oil and gas	131.1	261.3	55.7	1,263	138.4
Support Activities for Mining	63.7	148.7	46.9	1,253	77.9
Construction	23.7	56.9	13.5	303	25.7
Professional, scientific, and technical services	13.9	30.6	11.5	279	19.0
Households	12.4	21.9	4.3	81	12.6
Utilities	9.0	12.5	3.5	111	7.2
Total	**412.1**	**875.2**	**216.9**	**5,205**	**433.0**

Table 10-13 reports the economic impacts to the Uinta Basin of the ex situ oil sands scenario during its construction years. The $272 million assumed spent on Basin-based suppliers is shown to generate in the Basin an additional $400 million in business sales and $117 million of wage earnings associated with approximately 2,400 person-years of employment.

Table 10-13. Uinta Basin economic impacts attributed to the construction phase of the ex situ oil sands scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years
Machinery Manufacturing	104.5	145.8	42.3	873
Mining, except oil and gas	86.6	137.9	38.0	688
Support Activities for Mining	42.0	66.6	23.9	575
Construction	15.6	21.1	4.7	93
Professional, scientific, and technical services	9.1	13.6	5.1	105
Households	8.2	11.2	2.0	30
Utilities	5.9	4.0	1.2	38
Total	**272.0**	**400.2**	**117.1**	**2,401**

The difference in the construction-period economic impacts that arise from the oil sands scenario and those that arise from the oil shale scenarios is mostly attributed to the difference in expenditures between the scenarios. At $818 million, the C_{TPI} of the oil sands project is only 14% of that of the Tosco II oil shale scenario ($5.94 billion). In fact, simply scaling the impacts of the shale scenario by 0.818/5.94 gives a close approximation to the estimated impacts of the oil sands scenario because of the similarity in how the expenditures are allocated among the industries that are assumed to be the direct recipients of those funds.

10.4 Operations Impacts

As with the previous section, the following subsections give the economic impacts of the operations phase as measured by the RIMS II 60-sector IO model of Utah and the Uinta Basin, developed by the U.S. Department of Commerce, Bureau of Economic Analysis. For each scenario, the first two years of the operations phase are "ramping up" periods. During the first year of operations, production is 45% of full capacity. During the second year, production is assumed to rise to 67.7% of full capacity. During each of the third through twentieth years of operation, production is assumed to run at 90.41% percent of full capacity.

The operations expenditures for both scenarios are one of two types: variable and fixed. Variable costs are tied to the amount of production (i.e. to the utilization of capacity) while fixed costs are not. The fixed costs are no different during the ramp up period than during the steady state period. In contrast, during the first year of operations, variable operations costs will be 45% of what they would be at nameplate full capacity, or approximately 50% of the assumed steady state capacity (90.41%). During the second year of ramp up, variable costs will be 75% of what they would be during the steady state years. Economic impacts due to the operations phase will therefore be lower during the ramp up years than in subsequent years. The operations impacts reported in detail below are totals for all years of operation (ramp up and steady state).

Variable costs include utilities (water, fuel, electricity, etc). and other research and royalties for intellectual property. Fixed costs include the cost of labor, maintenance, and insurance.

Nameplate capacity is the nominal maximum capacity of the plant. Typically, the need to carry out maintenance prevents a plant from operating at its nameplate capacity for an extended period of time. The "operational capacity" is the part of the nameplate capacity that can be sustained over the long run.

Total operations expenditures include fixed and variable costs.

10.4.1 Ex Situ Oil Shale

Total operations expenditures associated with the Tosco II oil shale scenario over the 20 years of production are approximately $12.5 billion. When the region is "Utah," the regional share of this total expenditure is $6.27 billion (50% of the total). When the region is "Uinta Basin," the regional share is $4.14 million (33% of the total).

Table 10-14 reports the economic impacts to the State of Utah associated with the 20 years of the Tosco II ex situ oil shale scenario's operations phase. The $6.27 billion assumed spent on Utah-based suppliers is shown to generate an additional $11.0 billion in business sales, $2.50 billion of wage earnings associated with 59,000 person-years of employment, and $6.20 billion of GSP in Utah.

Table 10-14. State of Utah economic impacts attributed to the 20-year operations phase of the Tosco II ex situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	Value-Added
Utilities	2,827.5	4,999.9	968.7	18,535	2,868.0
Households	1,420.2	1,972.6	548.5	17,572	1,137.4
Mining, except oil and gas	1,195.1	2,381.2	508.0	11,514	1,261.7
Insurance carriers and related activities	378.8	729.9	204.7	5,135	462.0
Administrative and Support Services	202.9	378.6	81.5	1,780	162.2
Professional, scientific, and technical services	195.9	432.9	162.5	3,944	269.4
Chemical manufacturing	54.1	101.0	21.7	475	43.3
Total	**6,274.6**	**10,996.2**	**2,495.6**	**58,954**	**6,203.9**

Table 10-15 reports the economic impacts to the Uinta Basin associated with the 20 years of the Tosco II ex situ oil shale scenario's operations phase. The $4.14 billion assumed spent on Basin-based suppliers is shown to generate in the Basin an additional $5.22 billion in business sales and $1.25 billion of wage earnings associated with approximately 26,000 person-years of employment.

Table 10-15. Uinta Basin economic impacts attributed to the 20-year operations phase of the Tosco II ex situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years
Utilities	1,866.2	2,563.6	462.6	6,726
Households	937.3	633.0	183.1	5,978
Mining, except oil and gas	788.8	1,257.1	346.3	6,268
Insurance carriers and related activities	250.0	333.6	96.9	2,230
Administrative and Support Services	133.9	195.9	82.0	3,471
Professional, scientific, and technical services	129.3	191.9	71.7	1,485
Chemical manufacturing	35.7	45.4	8.0	146
Total	**4,141.3**	**5,220.5**	**1,250.7**	**26,304**

Total operations expenditures for the Paraho Direct oil shale scenario over the 20 years of production are approximately $11.7 billion. When the region is "Utah," the regional share of this total expenditure is $5.87 billion (50% of the total). When the region is "Uinta Basin," the regional share is $3.88 billion (33% of the total).

Table 10-16 reports the economic impacts to the State of Utah associated with the 20 years of the Paraho Direct ex situ oil shale scenario's operations phase. The $5.87 billion assumed spent on Utah-based suppliers is shown to generate an additional $10.4 billion in business sales, $2.25 billion of wage earnings associated with 50,500 person-years of employment, and $5.85 billion of GSP in Utah.

Table 10-16. State of Utah economic impacts attributed to the 20-year operations phase of the Paraho Direct ex situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	Value-Added
Utilities	3,470.3	6,136.6	1,188.9	22,749	3,520.0
Households	988.9	1,970.5	420.4	9,528	1,044.0
Mining, except oil and gas	934.3	1,297.7	360.8	11,560	748.3
Insurance carriers and related activities	201.3	387.8	108.7	2,729	245.5
Administrative and Support Services	134.6	251.2	54.1	1,181	107.6
Professional, scientific, and technical services	130.0	287.2	107.8	2,616	178.7
Chemical manufacturing	12.1	22.6	4.9	106	9.7
Total	**5,871.6**	**10,353.6**	**2,245.6**	**50,468**	**5,853.7**

Table 10-17 reports the economic impacts to the Uinta Basin associated with the 20 years of the Paraho Direct ex situ oil shale scenario's operations phase. The $3.88 billion assumed spent on Basin-based suppliers is shown to generate in the Basin an additional $5.05 billion in business sales and $1.13 billion of wage earnings associated approximately 21,900 person-years of employment.

Table 10-17. Uinta Basin economic impacts attributed to the 20-year operations phase of the Paraho Direct ex situ oil shale scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years
Utilities	2,290.4	3,146.3	567.8	8,255
Households	652.7	1,040.3	286.6	5,186
Mining, except oil and gas	616.6	416.4	120.4	3,933
Insurance carriers and related activities	132.9	177.3	51.5	1,185
Administrative and Support Services	88.8	130.0	54.4	2,303
Professional, scientific, and technical services	85.8	127.3	47.6	985
Chemical manufacturing	8.0	10.2	1.8	33
Total	**3,875.2**	**5,047.8**	**1,130.1**	**21,879**

10.4.2 Ex Situ Oil Sands

Operations expenditures associated with the ex situ oil sands scenario total $3.05 billion during the 20 years of production. When the region is "Utah," the regional share of this total expenditure is $1.53 billion (50% of the total). When the region is "Uinta Basin," the regional share is $1.01 billion (33% of the total).

Table 10-18 reports the economic impacts to the State of Utah associated with the ex situ oil sands scenario's operations phase. The $1.53 billion assumed spent on Utah-based suppliers is shown to generate in Utah an additional $2.75 billion in business sales, $622 million of wage earnings associated with approximately 15,000 person-years of employment, and $1.50 billion of GSP.

Table 10-18. State of Utah economic impacts attributed to the 20-year operations phase of the ex situ oil sands scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years	Value-Added
Mining, except oil and gas	660.1	1,315.3	280.6	6,360	696.9
Households	346.0	480.5	133.6	4,281	277.1
Utilities	325.9	576.3	111.7	2,137	330.6
Administrative and support services	62.1	115.9	25.0	545	49.7
Chemical manufacturing	60.6	113.0	24.3	531	48.4
Insurance carriers and related activities	40.3	77.6	21.8	546	49.1
Professional, scientific, and technical services	30.5	67.4	25.3	614	41.9
Total	**1,525.5**	**2,746.1**	**622.2**	**15,013**	**1,493.7**

Table 10-19 reports the economic impacts to the Uinta Basin associated with the ex situ oil sands scenario's operations phase. The $1.01 billion assumed spent on Basin-based suppliers is shown to generate in the Basin an additional $1.32 billion in business sales and $345 million of wage earnings associated with 7,400 person-years of employment.

Table 10-19. Uinta Basin economic impacts attributed to the 20-year operations phase of the ex situ oil sands scenario. With the exception of "Job-Years," all units are in millions of 2012 US$.

Industry	Regional Share	Sales	Wage Earnings	Job-Years
Mining, except oil and gas	435.7	694.4	191.3	3,462
Households	228.3	154.2	44.6	1,456
Utilities	215.1	295.5	53.3	775
Administrative and support services	41.0	60.0	25.1	1,063
Chemical manufacturing	40.0	50.8	9.0	164
Insurance carriers and related activities	26.6	35.5	10.3	237
Professional, scientific, and technical services	20.1	29.9	11.2	231
Total	**1,006.8**	**1,320.3**	**344.8**	**7,388**

10.5 Comparison with Similar Studies

This section provides context for the macroeconomic impacts reported above by comparing the present results with those of related studies on unconventional fuel development.

10.5.1 Ex Situ Oil Shale Impacts

The 2005 RAND oil shale study, *Oil Shale Development in the United States—Prospects and Policy Issues*, includes estimates of the job impacts associated with an ex situ oil shale industry growing at a rate of 200,000 BPD each year to a capacity of 3 million BPD [11]. In each year of years one through fifteen of the RAND scenario, a five-year construction period begins for four 50,000-BPD plants. Production and peak construction therefore commence at the beginning of year six. During peak construction, 20 new plants are under construction at any time with four finishing up each year.

Each 50,000 BPD plant is assumed to directly employ an average of 1,000 persons over the five-year construction period (i.e. 5,000 person-years per plant). RAND also assumes that the productivity of labor increased twofold since a 1980 estimate by the National Research Council of 1,600 persons per year, and therefore 800 persons per year are needed for operations labor. Based on employment multipliers developed by the Economic Policy Institute, every person-year of labor is assumed to give rise to 2–3 additional person-years of employment in the broader economy.

The jobs impacts vary over time, along with levels of construction and operations activity. In the first year of the scenario, 4,000 persons would be employed in the construction phase, and this would support an additional 8,000–12,000 person-years of employment. During year six, total direct labor would equal 23,200 persons (20,000 on construction, 3,200 on operations) supporting an additional 46,000–70,000 person-years of employment.

The RAND jobs impact estimate is based at that point in time where 3 million BPD of capacity is installed and construction continues at the same rate as before. At this point, total direct employment in the industry is about 70,000 persons (20,000 in new construction, 48,000 among 60 operating oil shale plants), supporting additional employment of between 140,000 and 210,000 persons in the broader economy.

This capacity level is attained by the 21st year of development.

The RAND method applied to construction of a single 50,000 BPD plant would estimate the nation-wide jobs impact at 10,000–15,000 person-years versus the 30,000–38,000 person-years for state-wide impacts and 14,000–17,000 person-years for Basin-wide impacts estimated in this report. The RAND estimates were computed under a somewhat different framework from those of this report, making it difficult to pinpoint the sources of the two- to three-fold difference in estimated labor impacts. Had the estimates of this report referred to national jobs impacts, the divergence between the estimates would have been considerably larger.

Applying the RAND method to the operations phase of a single 50,000 BPD plant, the estimated jobs impact is between 1,600–2,400 person-years each year, compared to this report's estimates of 2,500–3,000 job-years for the state-wide impact and 1,100–1,300 for the Basin-wide impacts. Again, since the RAND estimate is national in scope, these estimates are farther apart than they appear here.

10.5.2 Marcellus Shale Impacts

The 2011 report, The Pennsylvania Marcellus Natural Gas Industry: Status, Economic Impacts and Future Potential, provides estimates of various state-wide economic impacts due to construction and operation expenditures of the Marcellus shale gas industry [12].

Based on expenditures of approximately \$11.5 billion during 2010, the study estimates impacts to GSP of \$11.2 billion and 140,000 job-years of employment. The majority of this expenditure (\$7.4 billion) is from the drilling and completion of natural gas wells. The rest of total expenditures are based on lease and bonus payments (\$2.1 billion), pipelines and processing (\$1.3 billion), royalties (\$350 million) and miscellaneous other items (\$173 million).

Approximately 1200 horizontal wells at an average cost of \$5.4 million and 200 vertical wells at an average cost of \$1 million were drilled in 2010.

As noted earlier in this section, the fraction of expenditures spent on vendors in the study region (e.g. within the state) is a crucial parameter in economic impact analysis. The authors of the Marcellus study estimate that 95% of total expenditures were spent on vendors located in Pennsylvania. As in the study presented in this section, the authors of the Marcellus study synthesize the Marcellus natural gas industry out of the expenditures that compose it, since there is not yet a specific "shale gas" industry in the system of nation accounts on which the industry data of most IO models are based.

This 95% estimate is based on detailed accounting data collected by a survey of producers as part of a previous study.

To compare, this report assumes that 50% of expenditures are spent within the Utah study region and 33% of expenditures are spent within the Uinta Basin study region. Since total expenditures are approximately \$5–\$6 billion and \$820 million for the oil shale and oil sands scenarios respectively, the Utah share of expenditures is approximately \$2.5–\$3 billion and \$410 million respectively, while the Basin share is approximately \$1.7–\$2 billion and \$270 million respectively.

These percentages are assumed as there is no industry data to do otherwise.

Scaling the 2010 expenditures by the Marcellus industry down to the amounts assumed in this report for the state-wide case, it is seen that the estimated impacts per dollar spent in the state are quite similar. For example, scaling expenditures from 95% of $11.5 billion down to the $3 billion assumed for the Tosco II ex situ oil shale scenario in Utah, the jobs impacts is about 38,400 job-years (versus the 37,800 job-years estimated in this report). Scaling down to the assumed in-state expenditures for the oil sands scenario, the jobs impacts would be estimated as about 5,300 job-years (versus the 5,200 job-years estimated in this report).

Because the modeled impacts are linear in expenditures, the estimated impacts must be scaled too.

10.5.3 Alberta Oil Sands Impacts

In 2005, CERI published a study on the expected economic impacts due to the oil sands industry between the years 2000 and 2020 [13]. The study assumes that 14.7 billion barrels of bitumen would be produced over that period, 9.1 billion barrels of which would be upgraded to SCO. Estimated economic impacts to Alberta include C$634 billion of GDP, or an average of about C$30 billion per year, and 3.6 million person-years of employment impacts, or an average of about 170,000 person-years per year.

A "person-year" of employment (used in the CERI study) is the same as a "job-year" (used in this study) when it is assumed that each employed person is employed full-time. One job-year is consistent with one person employed full time for one year, two persons employed part time for one year, one person employed part time for two years, etc.

By comparison, the two ex situ oil shale scenarios considered in this report would produce about 318 million barrels of oil over their 20-year lifetimes and would generate in the state about 97,000 job-years and 81,000 job-years (construction and production phases combined) of employment for the Tosco II and Paraho Direct processes respectively. These ex situ oil shale scenarios thus involve about 2.7% of the oil production considered in the CERI study and estimated statewide job impacts are about 2.2–2.7% of what CERI estimates for Alberta. Using a basis of one million barrels of oil produced, the CERI estimate entails 245 job-years of employment while the ex situ oil shale scenarios in this study estimate between 245 and 309 job-years.

The CERI study also supplies estimates of the share of total expenditures which were spent in various regions for a typical integrated mining and upgrading project. Among total construction expenditures on goods, services and labor, 61% were spent in Alberta, 13% in Canada but outside Alberta, and the remaining 25% were imported from abroad. However, 100% of the labor was purchased within Alberta. The percentages are similar among total operations expenditures: 61%, 9%, and 30% respectively. Again, labor was sourced 100% within Alberta.

The results presented in this section assume 50% of expenditures are spent in Utah, which means 50% of the labor is sourced from Utah.

10.6 Conclusions

This section provides order-of-magnitude estimates of business sales, employment, associated earnings, and GSP impacts arising out of the construction and operation of oil shale or oil sands operations in the Uinta Basin. The impacts, measured with respect to both the statewide and Basin-wide economies, are very large, as might be expected for projects of such size.

Although this section provides impacts estimates, a central point is that economic impact analyses, as traditionally defined and carried out in practice, are best considered as order-of-magnitude estimates of changes in certain economic variables due to some project or policy introduced to a region. Because such estimates are imprecise and narrow in scope, they should be regarded cautiously and as part of a broader assessment of impacts.

10.7 References

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