5.0 DOMESTIC ENERGY RESOURCES

5.1 INTRODUCTION

This chapter is an examination of those U.S. energy resources — primarily fossil energy resources — best suited for synthetic fuels. For comparison purposes, examples of other forms of energy are examined briefly.

Estimated resources are defined as concentration of naturally occurring solid, liquid, or gaseous materials in or on the earth's crust in such form that economic extraction of a commodity is currently or potentially feasible. Estimates of resources are professional judgments based on a variety of geological data, exploration records, production histories, and various assumptions. As a sub-set of estimated resources, *proven reserves* are defined as those quantities which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known deposits under existing economic and operating conditions.

Table 5.1 is a summary of primary energy data — *estimated resources* and *proven reserves* — discussed above.

Table 5.1: U.S. Energy Supply (Ref. 32, 98)
(Billion barrels oil equivalent)

	Estimated Resources	Proven Reserves
Crude Oil	50 - 370	28
Natural Gas	56 - 210	36
Unconventional Gas		
- Coal seams	70	—
- Tight sands	—	38
- Devonian shale	—	2.9
- Geopressured brine	570 - 17,000	—
Tar Sands	26 - 37	2.5
Heavy Oil	55	1.8
Coal	4,500 - 17,000	1,200
Peat	29 - 250	—
Shale Oil	26,000	418

5.2 CRUDE OIL AND NATURAL GAS

5.2.1 Crude Oil

Petroleum resources — crude oil and natural gas — occur to some extent in almost every part of the world. Crude oil is produced in commercial quantities in more than 60 countries and natural gas in more than 50 countries. However, within those producing regions, commercially exploitable resources occur in very limited locations where geological conditions were appropriate for the formation and accumulation of the fluid hydrocarbons. The prevalent theory of hydrocarbon formation holds that petroleum and natural gas are the result of chemical conversion of organic plant and animal life which was deposited in regions where marine environments existed and thus supported extensive life. Petroleum is found primarily in sedimentary formations but rarely in igneous or metamorphic rock.

The composition of petroleum varies greatly. The quality of crude oil is characterized primarily by two properties: density and sulfur content. The standard density scale for petroleum is the American Petroleum Institute (API) gravity scale.*

The more valuable crude oils have a higher API gravity as they yield a higher fraction of gasoline. Sulfur is commonly expressed as a weight percentage of the total. Price is influenced by the sulfur content with low sulfur crude oils, normally less than 1% sulfur, commanding a significantly higher price than higher sulfur content oils. The price of low sulfur crude oil may be from 15% to 25% higher than a high sulfur crude oil of similar gravity. This is due to lower processing cost to achieve market specifications.

Crude oil is sold at a "posted" price which reflects current world market conditions. The posted price in a particular country may allow for a premium charge or a discount from the so-called "marker" crude

*API gravity is defined as:

$$\text{Degrees API} = \frac{141.5}{\text{Specific Gravity}} - 131.5 \qquad \text{Liquid Specific Gravity} = \frac{\text{Density}}{(\text{Water Density})}$$

price if the quality of the crude, that is, the sulfur content and gravity, vary from the quality of the marker crude. At present, the world marker crude is Arabian light. Crude oil is purchased under long-term contracts at posted prices or may be purchased in the "spot" market on a short-term or single cargo contract basis.

Although crude oil is produced commercially in more than 60 countries, the U.S.S.R, Saudi Arabia, and the U.S. produce half of the world production of 62.5 million barrels per day. Table 5.2 lists the ten largest producing countries, average daily production rate, and average well productivity for 1979. These ten countries account for three quarters of the world production.

(Ref. 10)

Table 5.2: Average 1979 Crude Oil Production (bbl/day)

	Country	Daily Production	Producing Wells	Productivity Bbl/day/well
1.	USSR	11,670,000	—	—
2.	Saudi Arabia	9,250,000	725	12,758
3.	United States	8,650,000	508,000	17
4.	Iraq	3,370,000	250	13,480
5.	Iran	2,900,000	547	5,301
6.	Venezuela	2,330,000	12,486	187
7.	Nigeria	2,310,000	1,457	1,627
8.	Kuwait	2,210,000	590	3,746
9.	China	2,100,000	—	—
10.	Libya	2,050,000	896	2,288

In the United States, crude oil exhibits a pattern of widespread commerical production with heavy concentration in a few areas. A total of 32 states reported some oil production in 1979, but 17 states accounted for essentially all of the crude oil produced. Production rates varied widely within these major producing states. For the major producing fields within the states, Arkansas produced a total of 3 million barrels in 1979 while Texas, the largest producer, reported a total of 686 million barrels. Table 5.3 illustrates the difference in production rate for new fields (e.g., Alaska) and older fields (e.g., Kansas). It must be recognized these averages are computed only for the larger, higher productivity fields. If all wells were included, the average productivity would be much lower. In the U.S., only the

Prudhoe Bay field in Alaska, where productivity is approximately 7,000 barrels per well per day, can approach the prolific 10,000 barrel per day wells, which are relatively commonplace in the Middle East.

Table 5.3: 1979 Crude Oil Production from Larger Fields in the U.S. (Ref. 11)

State	Production (thousands of barrels)	Estimated Number of Wells	Average Production per Well (barrels/day)
Alaska	505,462	377	4,060
Alabama	3,144	477	20
Arkansas	3,000	2,160	4
California	304,745	35,227	26
Colorado	19,306	445	131
Florida	35,904	100	1,088
Illinois	11,088	11,395	3
Kansas	6,042	4,880	4
Louisiana	199,032	12,823	47
Mississippi	9,979	515	59
Montana	9,621	1,156	25
New Mexico	36,607	3,860	29
North Dakota	3,651	369	30
Oklahoma	47,504	18,578	8
Texas	686,440	60,407	34
Utah	23,299	1,018	69
Wyoming	53,235	2,949	55

While a direct comparison of reported "reserves" of crude oil for each country may be somewhat misleading due to variations in definitions, it is nevertheless clear that the United States crude oil reserves position is not strong. Proven reserves are defined normally as the volumes of hydrocarbons recoverable under existing economic conditions using known technology. Table 5.4 lists the reserves positions of some of the countries which will affect future policy planning by the United States.

Table 5.4: Proven Reserves of Crude Oil, January 1, 1980 (Ref. 10)

Country	Reserves, (billion barrels)
Saudi Arabia	163.35
U.S.S.R.	67.00
Mexico	31.25
United States	26.50

Crude oil composition varies widely with location. In the U.S., the density of the crude oil being produced ranges from light East Texas crude of about 38° API gravity to California heavy oils of about 14° API gravity, which are extracted using steam stimulation. Sulfur content ranges from about 0.16% for some Alaskan crude to about 2% for some Texas crudes. Some foreign oils, including Middle-East, are close to 3% sulfur by weight.

5.2.2 Natural Gas

Natural gas has been formed over geological eons, probably in a manner quite similar to that which led to the formation of petroleum. Natural gas is often found along with oil in petroleum reservoirs, but many gas fields contain little or no petroleum. Various theories, including the migratory nature of the lighter hydrocarbons which comprise natural gas, have been postulated to account for the existence of natural gas without the accompanying petroleum — but none fully explains all conditions.

Natural gas is comprised primarily of the lightest saturated hydrocarbons — methane, ethane, propane, butane — along with sulfur compounds, carbon dioxide, nitrogen, water and, possibly, helium. Prior to marketing, the natural gas is usually processed in a stripping plant where propane and butane, and often a portion of the ethane, is extracted from the gas stream. Simultaneously, the harmful impurities and diluents such as hydrogen sulfide and carbon dioxide and water are removed. The propane and butane which are extracted are marketed separately as liquified petroleum gases (LPG) and the ethane is used as a petrochemical feedstock. Some natural gas streams contain a sufficiently high helium content to warrant extraction by special processing methods.

In many fields, as the natural gas is withdrawn and the pressure on the withdrawn gas reduced, hydrocarbons condense through a physical action called retrograde condensation. These liquids, composed primarily of hydrocarbons, in the C_5 plus range and commonly referred to as condensate or casinghead gas, are extracted prior to marketing the gas. While the liquids content of natural gas reservoirs varies widely, reported reserves of gas liquids indicate that for each million cubic feet of natural gas reserves there are approximately 29 barrels of gas liquids.

While natural gas production was reported for over 50 countries in 1978, more than three-fourths of the world's production and reserves was derived from the five countries listed in Table 5.5. The United States led in production, while the U.S.S.R., which has rapidly increased production in the past decade, was in second place.

Table 5.5: 1978 Natural Gas Production (Ref. 12)
(trillion cubic feet)

Country	Volume Produced
United States	19.9
U.S.S.R.	13.1
Canada	3.1
China	2.4
Iran	1.7
Other	13.7
Total	53.9

A significant fraction of the production identified as "Other" includes natural gas which is produced in association with crude oil and flared due to lack of world markets. Thus, the marketed production of natural gas for beneficial use is well below the total world production of 53.9 trillion cubic feet.

In the United States, natural gas is produced in 34 states but the major portion of the production is concentrated in four states — Louisiana, Texas, Oklahoma and New Mexico — which account for approximately 85 percent. The offshore region is playing an increasingly important role as a source of natural gas. For example, in 1977, 61% of the natural gas produced in Louisiana came from offshore fields.

The United States possesses the third largest volume of proved natural gas reserves in the world, exceeded only by the U.S.S.R. and Iran.

Canada and Mexico possess large quantities of natural gas which can be available for use within those countries or for export. Table 5.6 lists the estimated reserves for those countries which produce significant volumes of natural gas.

Table 5.6: Estimated Natural Gas Reserves (Ref. 10)

Country	Reserves, Trillion cu. ft.
U.S.S.R.	900
Iran	490
United States	195
Algeria	132
Saudi Arabia	93
Canada	86
Netherlands	60
Qatar	60
Mexico	59

While the United States produced approximately one-third of the world's natural gas, it possesses less than 10% of the proven reserves. The reserves/production ratio in the U.S.S.R. is approximately 70 while the ratio for the United States, including Alaska, is about 10.

Natural gas is composed primarily of methane. Other constituents, such as sulfur compounds, may be present in small quantities depending upon the particular well. The methane content of U.S. natural gas from Texas and Louisiana ranges from 66% to 99% with values of 90% and higher being typical. The heating value of a typical natural gas is about 1000 Btu/SCF although higher values — up to approximately 1400 Btu/SCF — are found in natural gas which contains relatively large amounts of ethane and propane.

5.2.3 Unconventional Natural Gas

In addition to the natural gas reservoirs discussed in Section 5.2.2, natural gas also exists in deposits from which recovery is not as easy or economical. In all cases the gas is a methane-rich mixture with minor amounts of other compounds. Heating value of the gas is typically over 950 Btu/SCF.

The four major potential future sources of unconventional natural gas in the U.S. are coal seams, tight gas reservoirs, Devonian shale, and geopressured brines.

Wherever coal occurs, some gas is associated with it. The amounts are greater per cubic foot of coal in deeper deposits. The tight gas formations are located chiefly in the Rocky Mountain regions. The principal deposits of Devonian shale are in the Eastern U.S. in Illinois, Michigan and Appalachia. Geopressured brine gas reservoirs are known to exist along the Gulf Coast, in the Mississippi salt basin of Mississippi and Alabama, the San Joaquin Valley (California) and certain Rocky Mountain basins.

The resource estimates for unconventional natural gas are derived from a relatively small amount of exploration data. Recent estimates suggest some 400 tcf in coal, 220 tcf in tight reservoirs, and 17 tcf in Devonian shale. Although very large, no good estimates exists for geopressured brines.

In the case of gas from coal, there are several major questions which affect recovery. Legal problems may arise concerning the ownership of the gas. The cost of collecting the gas by a system of wells, compressors and collection piping may be excessive. Operations, such as induced fracturing to improve gas collection, may cause safety problems when the coal is mined.

Similar problems exist in the case of gas from tight reservoirs. The cost of installing the necessary wells and increasing the permeability may be very high. Techniques to improve permeability involving explosives or hydraulic methods have been under development for over a decade; the best method will often depend upon the type of reservoir.

Although similar constraints exist for Devonian shales, large portions of the productive shale areas are already under lease and will be produced when the demand exists.

The technology for recovering gas from geopressurized brine is at a less developed stage than for the categories above. The major questions involve the recoverable amount of the resource and the costs associated with disposing of the brine which accompanies the gas. Proposals to recover the thermal energy of the brine produced are also being considered.

5.3 HEAVY OILS AND TAR SANDS

Considerable confusion exists over the meaning of the terms "heavy oils" and "tar sands." Heavy oil is considered to be a naturally-occurring form of petroleum which is fluid at formation conditions. Tar sands are porous rock or sediment deposits, containing petroleum constitutents not fluid at formation conditions. Hydrocarbon deposits, which require mining operations for recovery, are considered to be tar sands.

Another means of distinguishing between heavy oils and tar sands is by API gravity. Depending upon who is defining the cut point, values below either 15°, 12° or 10° API gravitiy, for example, may refer to heavy oil. As of December 21, 1979, crude oils with an API gravity less than 20% are considered heavy oils not subject to DOE price regulations.

5.3.1 HEAVY OILS

Approximately 2,000 heavy oil reservoirs are known to exist in the U.S. Of these, 951 are in Texas and 306 in California. Altogether, 16 states have significant heavy oil accumulations. The five states listed in Table 5.7 contain significant accumulations that are most susceptible to thermal recovery operations. Up to now, thermal recovery operations have been the most significant form of enhanced recovery technique applied to heavy oils.

Heavy oils are found in a number of foreign countries. One of the largest accumulations in the world is the Orinoco oil belt in Venezuela with an estimated one trillion barrels of resources. Other large accumulations are found in Canada and Russia.

Table 5.7: Thermal Recovery Reservoirs (Ref. 13)

States	Number of Reservoirs Most Susceptible to Thermal Recovery Operations
Texas	119
California	106
Arkansas	46
Wyoming	32
Louisiana	8

U.S. heavy oil resources with API gravity 20° or less and fluid at reservoir conditions are estimated at 55.5 billion barrels. California and Texas have the largest amounts estimated at 36.5 and 10.3 billion barrels, respectively.

Fluidity at reservoir conditons is evidenced by recovery of commercial quantities of oil by primary recovery. Thermal enhanced recovery methods, such as steam soak and/or steam drive, increase the formation fluidity, thereby allowing for a greater recovery of the oil in-place. However, depending upon formation characteristics, not all of the oil is susceptible to thermal recovery methods. Accordingly, recovery of heavy oils by thermal methods can be placed into three classes: Class 1 — most susceptible to current thermal recovery operations; Class 2 — somewhat susceptible; Class 3 — unlikely without major improvements in economics or technology.

Heavy crude oil is currently being produced by two methods — primary recovery and enhanced oil recovery. Primary recovery refers to conventional oil production techniques. Enhanced oil recovery currently includes thermal stimulation and carbon dioxide flooding. Other processes have been under development for many years with pilot test programs in operation in many parts of the nation. Most of the other methods of enhanced recovery, aside from simple water floods, are waiting for better economic prospects.

The oil industry initially attempted to produce heavy oils by drilling wells and pumping the oil to the surface. This approach met with limited success as evidenced by an in-place resource recovery of only 5-10%. Enhanced oil recovery methods are subsequently employed to increase the recovery.

Table 5.8 shows the U.S. resource position in heavy oils for 1975-1977.

Table 5.8: Heavy Oil Resource (Ref. 13)
(billions of barrels)

	Class I	Class 2	Class 3	Total
California	29.0	3.7	3.8	36.5
Texas	.7	2.7	6.9	10.3
Arkansas	3.9	.6	—	4.5
Wyoming	.8	.3	—	1.1
Utah	.6	—	—	.6
Louisiana	.4	—	—	.4
Alabama/Mississippi	—	1.4	.3	1.7
Oklahoma	—	—	.4	.4
	35.4	8.7	11.4	55.5

Much of the world's heavy oil production is currently achieved by some form of thermal stimulation. Essentially, steam is injected into the reservoir to reduce the viscosity of the oil so that it can be pumped to the surface. Steam soaking is a process whereby steam is introduced directly into the wellbore of a producing well for a period of four to five days. During this time, production is halted as the steam heats the formation surrounding the well, causing the oil to flow more freely. After this stimulation period is complete, the well is brought back into production, and shows markedly higher volume levels for the next four to five months, during which time the heated formation gradually cools and production declines until such time as the process is repeated. This form of thermal stimulation will recover an additional 7% over the amount already recovered by primary recovery. The steam soak process is extremely efficient since it yields about 25 barrels of oil per ton of steam injected. Considering that it requires approximately 0.6 barrels of oil to produce one ton of steam, about 40 barrels of oil are produced per barrel consumed.

Steam drive utilizes separate steam injection wells in the field, through which steam is constantly pumped into the producing zones under low pressure, driving the oil to producing wells. It is estimated that steam drive will recover an additional 14% over the amount already recovered by steam soaking. The process is, however, substantially less efficient than steam soaking in that only two barrels of oil are recovered per ton of steam injected. Expressed another way, only three barrels of oil are produced per barrel of oil consumed. It should be noted that the thermal stimulation recovery data is based upon recent Venezuelan Orinoco results.[14] Results will vary with fields and crude characteristics.

The capital costs associated with thermal stimulation are currently somewhat uncertain due to recently tightened SO_x and NO_x regulations. Nevertheless, the capital cost of eight 50 MM Btu/hr generators and one scrubber — adequate for 48 injection wells — is approximately $5 million. To this must be added the cost of the corresponding 48 injection wells estimated at $175,000 each for a well total of $8.4 million. Total capital investment is therefore on the order of $13.4 million or about $280,000 per injection well. Since one injection well is required per 1½ production wells, then approximately $185,000 must be added to the cost of each production well when calculating total capital costs per production well. Operating costs are estimated at $1.50-3.00 per barrel of fuel consumed and do <u>not</u> include the value of the fuel or taxes.

Two major environmental problems arise with steam soak and drive stimulation methods which are not encountered with primary recovery. Specifically these problems entail sulfur oxide (SO_x) and nitrogen oxide (NO_x) emissions arising from the combustion of produced heavy oil to generate injection steam. Sulfur and nitrogen contents are relatively high compared to "sweet" crude and are the source of the objectionable emissions.

To bring the generators into compliance with the applicable standards requires both SO_x and NO_x emission amelioration technology. The SO_x

emissions can be reduced by use of scrubbers employing sulfur absorbing chemicals. NO_x technology is also advancing with commercial prototypes now in service by several firms achieving acceptable results.

5.3.2 Tar Sands

Tar sands (known also as oil sands and bituminous sands) are deposits of porous rock or sediments impregnated with dense, petroleum, which is too viscous to be extracted by conventional petroleum recovery methods and which is not fluid at formation temperatures. Typically, the minerals comprising the sands are sand, sandstone or dolomite whose pore space can be occupied by water or tar. Pore space in U.S. tar sands ranges from 26 to 39 percent of the rock volume. The tar, which consists of many hydrocarbon compounds, is frequently referred to as bitumen — hence the alternative name, bituminous sands. The bitumen content of U.S. tar sands varies up to 18 percent of the total weight with 14 percent considered "rich."[15] Utah deposits tend to be less than 8 percent. Approximately 1½ tons of rich tar sands yield one barrel bitumen, the equivalent of about 6,300,000 Btu's.

In the U.S., 24 states have tar sand deposits. Of these, only the five states shown in Table 5.9 contain deposits of over a million barrels of bitumen.

Table 5.9: U.S. Tar Sand Deposits of 1 Million or More Barrels (Ref. 16)

States	Number
Utah	27
California	11
Kentucky	3
New Mexico	1
Texas	1

Canada possesses greater tar sands deposits than the U.S., with the largest being the Athabasca deposits of the Province of Alberta. Recognizing the immensity of this resource, two commercial ventures — Great Canadian Oil Sands, Ltd. at approximately 50,000 barrels per day (B/D), and Syncrude Canada, Ltd. at approximately 100,000 B/D — are already in operation.

A number of parameters provide the distinction between resources and proven reserves. These include overburden thickness, bitumen concentration, total size of deposit, friability of the sands and overburden, and availability of overburden and tailings storage. A rule of thumb[17] is that a project is uneconomical when the overburden/sands ratio exceeds 1.I and the bitumen content is less than 20 gallons per ton of tar sands.

As shown in Table 5.10, the Venezuelan, Canadian, and USSR reserves are much larger than those in the U.S.

Table 5.10: International Tar Sand Resources (Ref. 18)
(billion barrels)

Country	Resources
Venezuela	1050
Canada	890
USSR	134
United States	24
Others	102
	2200

From Table 5.11, Utah clearly has a predominant position in the U.S. with approximately 95% of the domestic resources.

Table 5.11: Domestic Tar Sands Resources (Ref. 19)
(million barrels)

State	Resources
Utah	23,200-29,500
California	1,400-3,100
Texas	124-3,000
New Mexico	57-60
Kentucky	34-37

Significant deposits also occur in Missouri, Alabama, Oklahoma, and Kansas.[17]

Saturation data covering the weight ratio of bitumen contained within the U.S. tar sands is available, although not on an extensive basis. Current data indicates a broad range on the order of zero to 18%. Kentucky deposits are relatively lean while those from California are the richest, averaging approximately 12%. Utah, with the largest reserves, varies widely with values ranging from 1% to 17%. Canadian Alberta sands have bitumen saturation values quite similar to those found in Utah.

There are two basic approaches towards recovering the bitumens contained within the tar sands. One involves aboveground mining of the sands, followed by bitumen extraction and upgrading, and waste disposal. The other involves an *in situ* extraction and upgrading.

The choice between aboveground mining or *in situ* recovery is dictated by the overburden depth and ratio of depth to deposit thickness. Aboveground mining to depths of 150-200 feet[18] requires a ratio of 1.0 or less (Great Canadian Oil Sands ratio is approximately 0.4) and a bitumen content greater than 10% by weight. On the other hand, *in situ* processing requires a minimum overburden depth of 500-1000 feet to maintain pressure control during processing. Currently there are no viable methods to recover the bitumen at depths between 200-500 feet.

At the two operating plants in Canada, the tar sands are mined by using either bucket wheel excavators or draglines. After transportation to an extraction unit, usually a K.A. Clark hot water unit, the bitumen is separated from the water wet sands. The bitumen is then subjected to appropriate refining techniques which produce a synthetic crude oil. The spent mineral matter must be removed to a disposal area. The Clark process may not be applicable to all U.S. tar sands deposits.

To provide a perspective on the magnitude of the mining operation, 221,000 tons per day of material must be handled to provide 50,000 bbl/day of bitumen.[17] Of this amount, 110,500 tons per day are tar sands which would be sent to the bitumen extraction unit. The tailings from this unit, estimated at 100,000 tons per day would go to storage and eventually to reclamation. The balance, which is overburden, would be used in reclamation. These calculations are based on a bitumen content of 20 gallons per ton, a 1.0 overburden ratio, and a 95% extraction efficiency.

In situ processes have never been used on a commerical scale, although a number of techniques have been studied in pilot operation. The techniques used most extensively employ conventional crude oil secondary and tertiary recovery methods.

In situ processing involves separation of the bitumen from the sands, thereby eliminating mining and transportation of the tar sands as well as disposal of the tailings and overburden. Thermal or chemical means may be used to affect separation. Thermal processes involve heating the formation with either steam, hot water, or hot gases produced by combustion in the tar sands zone. Chemical processes involve the use of solvents and/or emulsifiers which can be pumped through the formation to strip the bitumen from the sand.

Environmental considerations can provide substantial operational problems for aboveground plants due to the plants having the characteristics of both an open pit mine and a processing unit. The residuals produced by the mining, namely, large quantities of overburden and tailings, dust and vehicle emissions into the atmosphere, and water pollution from mining and processing all fall under the regulation. Furthermore, also applicable to the mining operation is the Clean Air Act Amendments of 1977, which includes requirements for air emissions offsets, the prevention of significant deterioration and the use of best available technology as part of the new source review procedures. In addition, recognition must be given to the groundwater table, violation of which may require potentially expensive aquifer protection.

The *in situ* recovery option is more acceptable environmentally since most of the residuals generated by aboveground mining are not produced. However, the *in situ* operation does produce leachate which is not encountered in the aboveground mining. Whether the leachate produced will result in adverse environmental impacts is as yet an unanswered question, but one that must be anticipated.

5.4 OIL SHALE

Oil shale is a hard rock which contains a minor fraction of an organic material called kerogen. When kerogen is heated in the range of 400 to 500°C, a process called retorting, it decomposes into hydrocarbon liquid and gas leaving a carbonaceous residue. The liquid is shale oil which differs from ordinary petroleum oil due to a lower hydrogen content and a higher viscosity. As produced from a simple retorting process, the shale oil is too viscous to send through pipelines. Hydrotreating the shale oil reduces the viscosity and some of the undesirable impurities such as nitrogen and sulfur.

Oil shale is commonly rated for oil content by a standard lab method called the Fischer Assay. The results are expressed in gallons of oil per ton of shale (GPT). In the U.S.A., a richness of 25 GPT or more is considered high quality.

There are significant formations containing oil shale in Colorado-Utah-Wyoming, and in some of the central and eastern states. The richest deposits in the U.S. are in the Green River formation in Colorado-Utah-Wyoming; those in the central and eastern states are less rich and more scattered geographically. A map for known U.S. deposits is given as Figure 5.1.

The amount of oil in place in the form of U.S. oil shale has been estimated at over six trillion barrels. The amount of this oil which is recoverable within realistic economic constraints is far less, but cannot be stated with any accuracy since there is no actual commercial production experience.

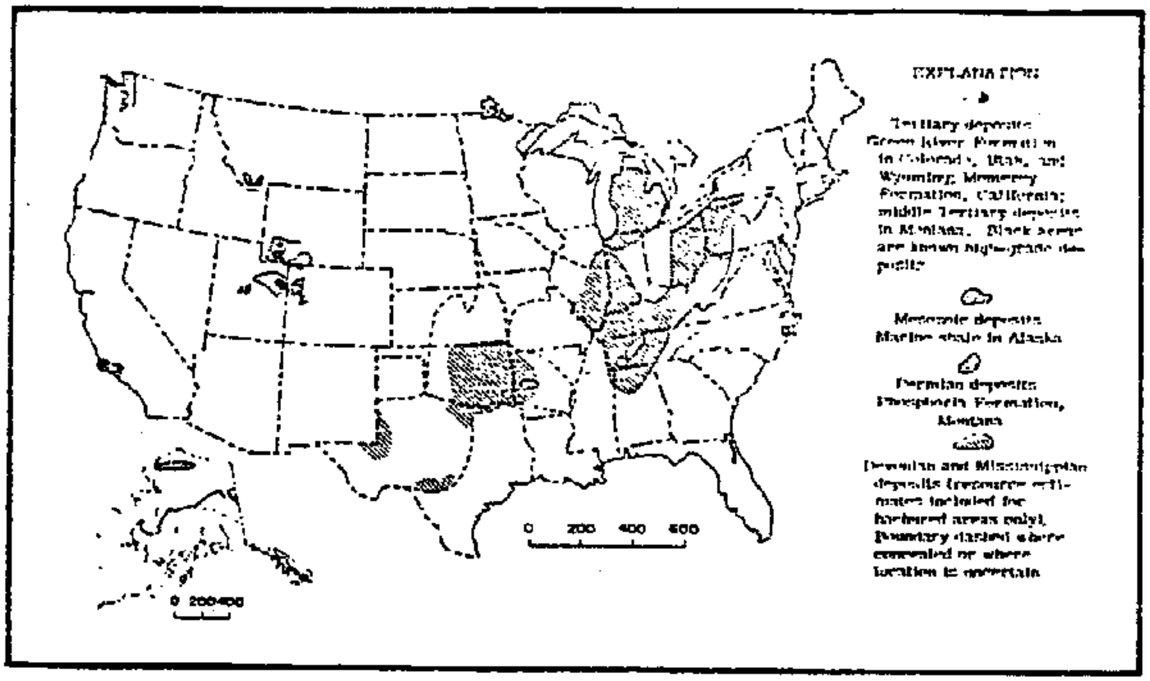

Figure 5.1: Known Oil Shale Deposits of the United States (Ref. 76)

A reasonably accurate appraisal of the amount of oil shale in place for the Green River Formation is shown in Table 5.12.

Table 5.12: Potential Shale Oil Resources of the Green River Formation (Ref. 16)

Location	Shale Grade Gallons Oil/Ton			
	5-10	10-25	Over 25	Total
Piceance Creek Basin (Colorado)	200	800	480	1,480
Uinta Basin (Utah)	1,500	230	90	1,820
Green River Basin (Wyoming)	300	400	30	730
	2,000	1,430	600	4,030

The potential shale oil in place for the entire nation is shown in Table 5.13. Inconsistencies between Table 5.12 and 5.13 are a reflection of the wide range covered by estimates of shale oil resources.

Table 5.13: Potential Shale Oil in Place in the Oil Shale Deposits of the United States (Ref. 20) (billions of barrels)

Location	Range of Shale Oil Yields, Gallons Per Ton		
	5 - 10	10 - 25	Over 25
Colorado, Utah, and Wyoming (the Green River formation)	4,000	2,800	1,200
Central and Eastern States (includes Antrim, Chattanooga, Devonian, and other shales)	2,000	1,000	(?)
Alaska	Large	200	250
Other deposits	134,000	22,500	(?)
Total	140,000	26,500	2,000(?)

Doubts concerning actual shale oil reserves exist for many reasons, including sparse core hole data, uncertainty of overburden removal requirements, uncertainty of commercial retorting results, and development cost uncertainty due to environmental obstacles. Another important consideration is ownership. The vast majority of the richest shale land is owned by the Federal government, as is shown in Figure 5.2

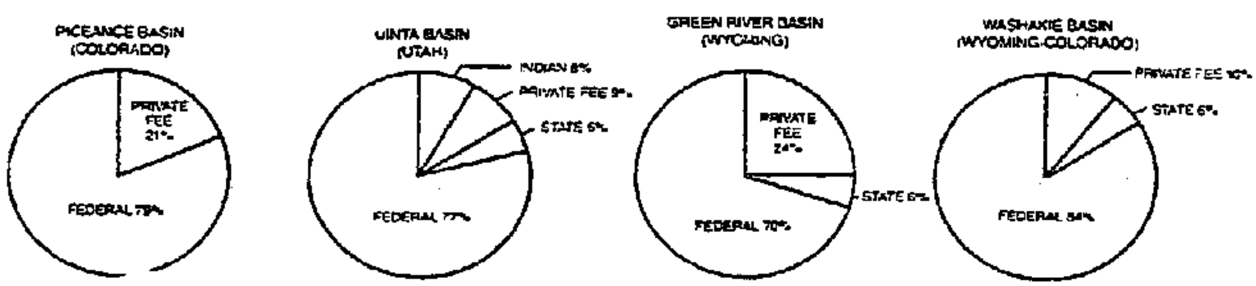

Figure 5.2: Ownership of the Oil Shale Lands of the Green River Formation (Ref. 20)

Oil shale varies widely in oil richness from one deposit to another and within any given deposit. The kerogen is always found within stratified layers. No feasible method has been found for mechanical separation of kerogen from the inert rock. Thus, the retorting process suffers the inefficiency of having to supply heat for a large amount of useless rock.

Kerogen comprises about 15 wt% of 25 GPT oil shale. Kerogen molecular weights have been estimated in excess of 3,000 and they vary with the deposit. The retorting of kerogen results in approximately 66 wt% oil, 9% gas, 5% water and 20% carbon residue. As with any very complex species, these functions will vary with the deposit.

The particular materials which comprise the inert portion of the oil shale depend strongly upon the deposit location. All of the Western oil shales contain dolomite and calcite. Some of the Green River oil shales contain nahcolite, a mineral rich in sodium bicarbonate, and aluminum compounds. Nahcolite offers potential as a flue gas treating agent to remove sulfur compounds.

The mining of oil shale is more like hard rock mining than coal mining. There is a large amount of mining required for either surface or modified *in situ* (MIS) shale oil production.

A surface retorting operation may be supplied with shale from either open pit or conventional mines. Underground room and pillar mines leave about 40% of the resource behind as pillars and walls that cannot be removed. Development plans have been proposed which provide for surface retorting in the first stage followed by *in situ* retorting.

What has been termed true *in situ* retorting does not involve any mining beyond the drilling of access wells for gas injection and product removal. Since oil shale is normally impermeable, TIS methods must include some way to establish flow between the inlet and outlet wells. This part of the procedure involves much uncertainty. Equally uncertain is the portion of the enclosed resource that will be recovered before short-circuiting between inlet and outlet wells occurs.

MIS retorting has greater prospects than TIS for commercial-scale operation, and development work has been underway for most of the past decade. With MIS, an underground vertical retort is constructed by mining a portion of the shale conventionally, and then taking advantage of the access to fracture four to five times the volume of the removed portion in place, using explosives. The rubbled oil shale bed is then ignited from the top and air supplied by injection. The heat of combustion supplies the retorting energy, and oil and gas are recovered. The carbon residue is all burned to supply heat. Uncertainties still remain about the competitive advantages for this method on a large scale. The status for commercial and development shale projects is described in Section 6.3.

The costs for the mining portion of the process depend very strongly on mine type, scale of operation, shale depth, and other factors peculiar to the site.

Water availability is a major consideration throughout the Green River area where the best commercial potential exists. MIS retorting is claimed to provide more oil for the same amount of process water; however, this method has potential for contamination of groundwater tables from leaching of spent retorts. Water supply may not necessarily be a critical constraint as there is the possibility of pipelining water to Green River shale oil conversion projects.

The available technology to meet air quality requirements appears to be sufficient, but commercial experience is lacking. A series of studies has concluded that air quality requirements can be met without prohibitive costs.

The safety and land reclamation aspects of the environment requirements can be met by known methods. The particular requirements depend