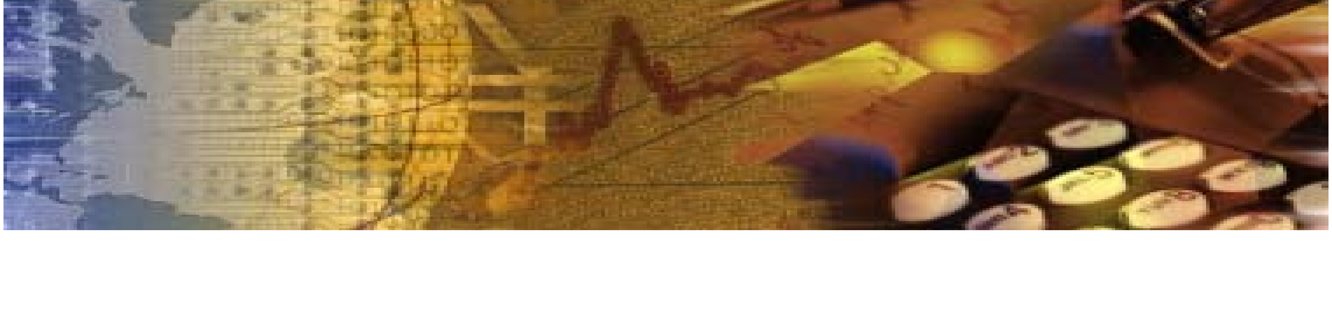
Energy Potential and Metrics Study—An Alberta Context



Prepared For

Alberta Department of Energy

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Acronyms and Terms

Acronym or Term	Definition
AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
Behind-the-fence	Generation that takes place within the battery limits of an industrial facility
Bitumen	Petroleum in solid or semi-solid form
BOS	Balance of system – in a solar PV system the system components that are not part of the cell modules
CanSim	Canadian socioeconomic database from Statistics Canada
Capacity Factor	A term used in electricity generation that compares how much electricity a generator actually produces with the maximum the generator could produce at continuous full power operation during the same period.
CBM	Coal Bed Methane - Natural gas generated and trapped in coal seams
CCS	Carbon Capture and Sequestration – a technology to reduce carbon emissions released to the atmosphere by capturing carbon dioxide from process emissions. The carbon dioxide can then be used a feedstock, in enhanced oil recovery or stored underground indefinitely.
CNG	Compressed natural gas
CO_2e	Equivalent carbon dioxide emissions – for a given mixture of greenhouse gases, measures the equivalent global warming potential of the gases as if all of the gases were carbon dioxide over a given time period (usually 100 years)
Cogeneration	Simultaneous generation of heat and electricity in the same facility
Conventional petroleum	Petroleum found in liquid form, flowing naturally or capable of being pumped without further processing or dilution.
CSS	Cyclic Steam Stimulation – an in situ method to recover bitumen from an underground deposit
Dil-Bit	A mixture of diluent and bitumen that that meets pipeline standards for viscosity and density

Acronym or Term	Definition
Diluent	Light hydrocarbon stream that is used to dilute bitumen to make the final mixture meet pipeline standards.
EGS	Enhanced Geothermal Systems – a method of extracting geothermal energy by stimulating flow via controlled reservoir fracturing
EIA	Energy Information Administration – a US governmental agency that tracks, reports and forecasts energy industry related statistics
Energy commodity	As used in the Study, the end product of the resource and pathway that can be used by the consumer; either heat, transportation fuels or electricity
ERCB	Formerly Energy Resource Control Board, now AER
Established reserves	The portion of the discovered resource base that is estimated to be recoverable using known technology under present and anticipated economic conditions. Includes proved resources plus a portion of probable resources.
FCC	Fluidized Catalytic Cracker – a process unit in a refinery that makes long chain carbon molecules into shorter molecules to improve gasoline yields
GHG	Greenhouse Gases – gases in the atmosphere that adsorb and emit radiation within the thermal infrared range. Gases typically cited as greenhouse gases include CO2, N2O, methane and fluorocarbons.
GSHP	Ground source heat pump – a unit that extracts heat from the ground or from a body of water to use for space or water heating. The process may be reversed to be used for air conditioning
GWP	Global Warming Potential - a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of a greenhouse gas to the amount of heat trapped by a similar mass of carbon dioxide.
HHV	Higher Heating Value – Heat released by the combustion of a certain mass of a substance. This heating value takes into account the latent heat of vaporization of water in the combustion process. This assumes that the water in the combustion process is a liquid at the end of the process.
HVAC	Heating ventilating and air conditioning

Acronym or Term	Definition
IEA	International Energy Agency – an autonomous organization that focuses on energy security, economic development, environmental awareness, and engagement worldwide
In situ bitumen recovery	In situ recovery refers to various methods used to recover deeply buried bitumen deposits, including steam injection, solvent injection and firefloods.
LHV	Lower Heating Value – Similar to the HHV but does not take into account the latent heat of vaporization of water. It assumes that the water is a vapour at the end of the combustion process.
LNG	Liquefied Natural Gas – natural gas that has been compressed and chilled until it reaches a liquid state
MSW	Municipal Solid Waste
Naphtha	Mixture of hydrocarbons generally having 5 – 12 carbon atoms
Natural Gas Liquids	Liquids obtained during natural gas production, including ethane, propane, butanes and condensate.
Non-renewable resource	A resource that does not renew itself at a sufficient rate for sustainable economic extraction in meaningful human timeframes.
Oil Sands Development Group	A non-profit oil sands industry-funded association, based in Fort McMurray, that facilitates solutions to shared development issues related to the Athabasca Oil Sands Deposit in Alberta.
Partial upgrading	Process to change the structure and composition of bitumen to make a crude oil that meets pipeline standards but is not as improved as a synthetic crude oil that has been fully upgraded.
Platformer	A refinery unit that uses a platinum catalyst to make gasoline blending components with improved gasoline octane
PV	Photovoltaics – A method of generating electrical power by converting solar radiation into electricity by using semiconductors that create electric current upon exposure to sunlight.
R&D	Research and Development
SCO	Synthetic crude oil - Bitumen that has been modified through the upgrading process to have properties that are similar to a light, low sulfur crude oil

Acronym or Term	Definition
Syn-bit	A mixture of synthetic crude oil and bitumen

Conversion Factors

General Conversions and Factors	
Time	
hours/year	8,760
days/year	365
hours/day	24
minutes/hour	60
Mass	
lb/Short Ton	2000
lb/Long Ton	2,240
kg/lb	0.453592
Volume	
scf/lb-mole	379.50
ft^3/m^3	35.31
gal/bbl	42.00
l/gal	3.78541
gal/ft^3	7.48
Volume in a mole of gas at STP, l/mole	22.40
Distance	
km/mile	1.609344
m/ft	3.281
Area	
m^2/hectare	10,000
Acre per hectare	2.47
Temperature	
°F to °R	456.67
STP Temperature, °K	273.16
Standard conditions for gas - English system, °F	60.00
Standard conditions for gas - Metric system, °C	15.00
Standard conditions for gas, °K (assumes 60 °F)	288.72
Energy	
J/BTU	1,055.05
(Btu/hr)/hp	2,544.43
kW/hp	0.75
BTU/kW-hr	3,411.80
MJ/kWh	3.6
kWh/MJ	0.2778
Barrel of oil equivalent, BTU/bbl	5,800,000
Barrel of oil equivalent, GJ/m^3	38.48
Convert Gravity	
API from Specific Gravity	API=141.5/SG-131.5
Specific Gravity from API	SG= 141.5(API+131.5)
Prefixes	
Mega (M)	10^6

General Conversions and Factors	
Giga (G)	10^9
Tera (T)	10^12
Peta (P)	10^15
Exa (E)	10^18

Executive Summary.

Executive Summary

The Alberta Government (the Alberta Department of Energy) contracted Jacobs Consultancy Canada Inc. (Jacobs Consultancy) in 2012 to carry out an *Energy Potential and Metrics Study—An Alberta Context* (the "Study") to more systematically understand the range of energy resources that could potentially supply energy to meet Alberta's needs and do so in a manner that would further the characterization and comparison of energy resources. Jacobs Consultancy and the Alberta Department of Energy formed a Study Team, which was guided by a Technical Steering Committee who reviewed the work and offered comments and direction throughout the Study.

The report includes a comprehensive view of all major energy resources in Alberta and the pathways that are used to create basic energy commodities used in Alberta, namely, heat, electricity and transportation fuels. We use a broad spectrum of metrics to enable the reader to understand energy availability, energy density, and the environmental impact of a wide range of energy resources and pathways in Alberta. An important deliverable of the report is to provide a resource for energy literacy and to give the reader an improved perspective on Alberta's energy supply.

The Study is intended for a broad audience representing environmental interests, the energy industry, academia, and groups involved in setting government regulations and policy.

Study Objectives

The Study is a first-order engineering assessment of Alberta's energy resources intended to facilitate an understanding of Alberta's energy resource potential based on assessing all resources in a comprehensive and consistent manner. Key to this analysis is the overall material and energy balance for each Alberta-based primary energy resource that highlights the potential of each resource to supply the commodity energy products - electricity, transportation fuels, and heat. The use of a broad span of consistent metrics to assess each resource provides a thorough analysis of the issues regarding the potential of each resource to supply energy for Alberta. The Study followed a methodical, sequential analysis for each energy resource.

The scope of the Study was as follows:

1. Identify the gross resource base for primary energy resources in Alberta: natural gas, coal, oil, biofuels, biomass, hydroelectric power, landfill gas, municipal solid waste, solar energy, geothermal energy, wind power, and nuclear energy.

2. Define the potential of each energy resource to produce commodity energy for end use - electricity, transportation fuel, and heat.
3. Through a technical assessment, identify the potential of each primary energy resource and any associated technical attributes that may be considered barriers to the development of this resource.
4. Use a set of metrics to evaluate the material and energy balance characterizations of the pathway for each energy resource to deliver the commodity energy products: electricity, transportation fuel, and heat. Application of these metrics is intended to provide greater certainty about the resource input and conversion steps to deliver the commodity energy as well as information to characterize each pathway, including energy yield, associated loss, and environmental impact.
5. Provide current resource potential estimates for each energy commodity and comment on how, with technology improvements, these estimates may change over the next twenty years.
6. Provide well-documented references based on publicly available sources for all data.
7. Clearly show all assumptions and calculation methodologies.

Energy Characteristics

Energy is foundational and a key input to our standard of living and way of life. As a result, energy resources and the social/political/economic structures they support are interdependent. They evolve together and change in response to market and economic conditions.

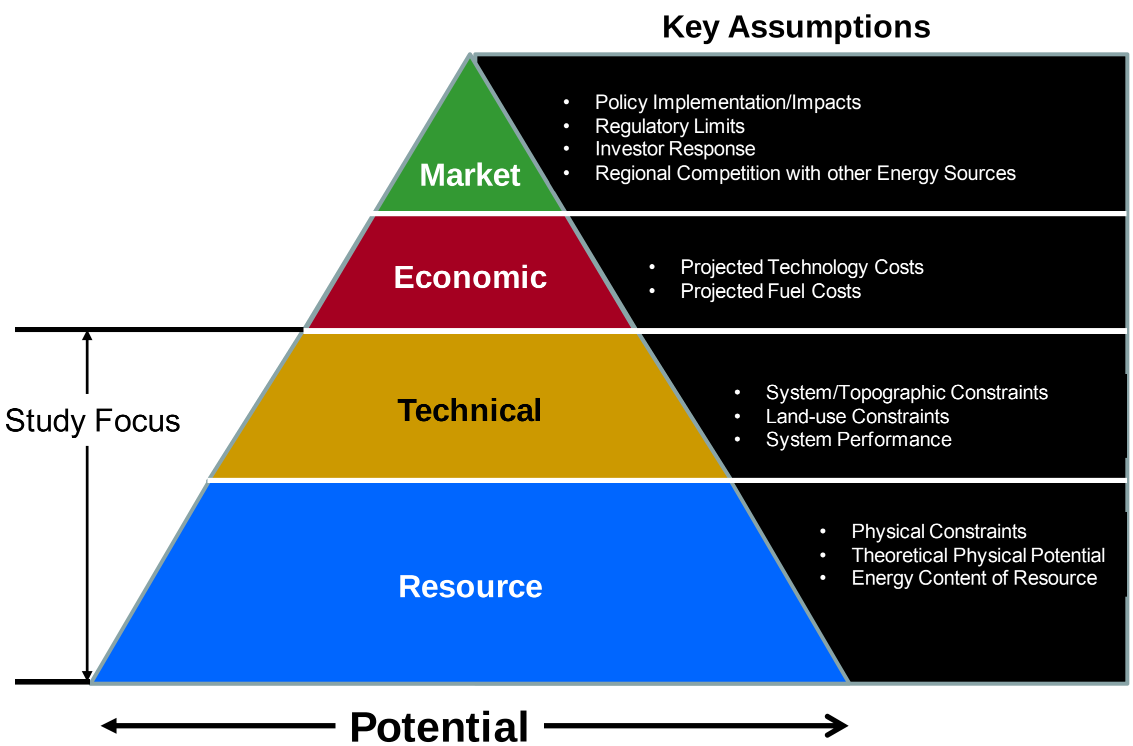
Energy comes in many forms and is used in many ways. The use of energy resources involves decisions. For example, consumption of fossil fuels (natural gas, oil, and coal) contributes greenhouse gas (GHG) emissions to the atmosphere. Consumption of non-renewable energy sources raises potential risk of running out of these sources once the resources are depleted or become uneconomic to recover. Consumption of renewable fuels may be limited by their availability, may face technical constraints on total production, might compete with food production, or require greater use of marginal land and limited water supplies. Consumption of energy sources that are not produced locally raises concerns about energy security. Some energy sources are best suited to supply electricity. Others are better suited to supply transportation fuels. Some resources are available in high energy density on a consistent basis, others less so.

Figure ES.1 depicts in schematic form the hierarchy of steps in understanding energy resources.

- The base of the pyramid is focused on understanding the potential of each energy resource based on its breadth, accessibility and physical constraints.
- The second level of the pyramid depicts understanding the technical limitations found in exploiting the energy resource, such as land use and environmental limitations, ease of physical recovery and conversion of the resource to commodity energy products; it includes the efficiencies of each step along the energy pathway. The metrics developed in the Study describe the potential of each energy resource and the technical parameters governing its development and conversion to commodity products.
- The third level deals with economic understanding of each energy resource, including technology costs, distribution infrastructure, input and output costs.
- The fourth level shows the key external factors that affect energy sources: societal constraints set by regulations, response by investors, and by other energy competitors.

While there may be a natural tendency to jump to evaluation of economics and external factors when trying to compare energy sources, in this Study we will focus on understanding the bottom two steps in the pyramid in order to set a solid foundation for the next phase of work. A subsequent study would evaluate economics and external factors affecting energy resource development and deployment for Alberta.

Figure ES.1
Understanding the Development of Energy Resources



Source: National Renewable Energy Laboratory (NREL), 2012

Establishing Study Boundaries, Fundamental Principles and Assumptions

Our intent is to provide energy metrics on a transparent, first principles engineering basis, using the following Study boundaries:

- The Study only addresses energy technologies in the context of Alberta.
- The Study does not address projected market share of an energy commodity.
- The Study does not address end use energy cost (i.e. cost of bringing the energy commodity to the consumers).
- The Study does not address the effects of policy on energy development.

Overview by Technical Steering Committee

The Technical Steering Committee met with the Study Team on a regular basis. They helped set the basis for the Study. They provided technical information in their respective areas of expertise, and reviewed project progress and technical results. Meetings were held in Calgary and by teleconference/webconference. Technical Steering Committee members came from industry, primarily in Alberta, academia, and government agencies in Canada, at both the federal and provincial level.

Energy Attributes

While many types of energy are fungible, there are key features of supplied energy that must be considered when determining energy substitution or a new mix of sources.

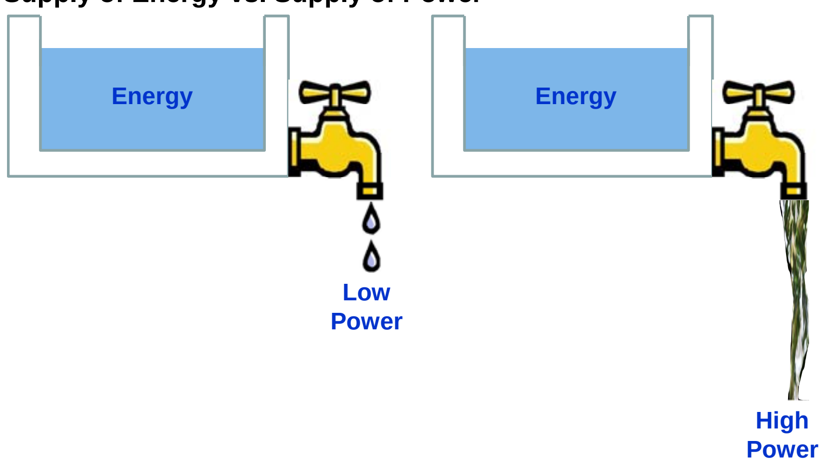
Delivering Energy to the Customer

Understanding the needs of the energy commodity consumer is a key factor in determining the potential for energy commodity production. In general, consumers prefer energy commodity supplies that are readily available, that are competitively priced, that can deliver the required energy at the required rate and that have low environmental impact. More specifically, electricity consumers require reliable supply that is available on-demand at a stable voltage. Consumers of transportation fuels require fuels that can be safely stored on-board the vehicle at sufficient energy density to meet their transportation needs. Heat must be supplied at the correct temperature and at the rate required.

The needs of the industrial consumer differ from those needs of the residential or commercial consumer. The industrial consumer often will require heat at much higher temperatures than a residential or commercial consumer. For example, the heat needs of an in situ bitumen producer are quite different from the heat requirements of a family home in terms of both quantity and temperature. The industrial customer also may require electrical power at much higher voltages than a residential or commercial customer. An example would be the difference between residential electrical demand as compared to that of a large data processing center or an electric arc furnace operator. Industrial consumers may have the ability to manage loads so that they can purchase electricity during low demand / low cost periods. For example, data centers can shift certain heavy loads to the nighttime when costs are lower.

We also must differentiate between the supply of energy and the supply of power. This is a critical differentiation, commonly overlooked in the discussion of energy supply. Energy is the capacity to do work, whereas power is the delivery of energy over time. As shown in Figure ES.2, two resources may contain the same amount of energy but differ in their ability to supply power. In considering energy supply we must consider delivery of energy at the rate needed by the consumer.

Figure ES.2
Supply of Energy vs. Supply of Power



Stock versus Flow

Another way to differentiate energy resources is to consider the differences between those based on a stock of resource reserves versus those based on a flow of the resource.

Stock-based energy resources are supplied from a reservoir of stored capacity that is much greater than the annual production of the resource. Increased rates of energy production are realized by capital investment or technology improvements that enable more energy to be drawn from the reservoir at a faster pace. These reservoirs have a finite limit of resources and are not replenished. Measurements of reserves can be made based on criteria such as extent of exploration and the cost of recovery. However as new recovery techniques are developed and the economics of resource recovery change, the quantity of material in existing reserves can change. Examples of stock based resources include coal, oil, natural gas, and uranium.

Flow-based resources are not produced from reservoirs and thus there is no inherent storage capability or reserves for these types of resources. The rate of production of the energy resource depends on the rate that the resource is available. Flow-based resources are replenished more or less continuously but the rate of replenishment may change over time. There may or may not be some short-term storage potential, but not nearly enough to overcome long periods of scarcity. Examples of flow-based energy resources are those based on wind, solar, and biomass.

Some resources are hybrids of stock and flow. There may be a reservoir of the resource that is replenished but the rate of replenishment is slow. An example of a hybrid resource is timber; it may take many years to replenish existing forest stock. Hydroelectric power is also a type of hybrid resource, but for different reasons. Run of river hydroelectric power is generally a flow resource. Dam-based hydroelectric power is more like a stock resource with slow annual replenishment. Geothermal energy is another type of hybrid energy resource because the rate of energy production often depends on the rate that heat is resupplied. If we draw too much energy too quickly, the geothermal resource may become depleted until the energy is resupplied from the earth.

Electricity Generation Characteristics

The Alberta electrical grid currently is supplied by a range of resources which follow different pathways to deliver electricity and which have different grid supply characteristics. The challenge to the electricity grid operator is how to balance these different characteristics and still supply electrical power that meets the needs of the consumer. Three key characteristics to describe the electricity sources are dispatchability, variability and intermittency.

- Dispatchability is the ability of the power generator to ramp up or down power production when the grid requires a change in power delivery.
- Variability is the change in the supply of power to the grid based on changes that are not within the control of the power plant operator. For example, gusty winds will change the output of a wind turbine, or clouds will change the output of a solar cell.

- Intermittency is the extent to which a power source is unintentionally stopped or unavailable. Intermittency may be predictable such as the diurnal nature of solar power.

Grid operators are facing increasing challenges in supplying electricity. Demand for electric power is increasing as is the demand for power quality. Concerns about greenhouse gas emissions are leading to a decreasing supply of low variability / intermittency and moderately dispatchable power supplies as a result of the reduction in coal-fired power plant capacity. Increased use of low dispatchable and highly variable resources such as wind requires increased planning, new technologies and system support services for the grid operator. New technologies and management strategies being developed and implemented for the grid operator to manage these new challenges include:

- Increased integration with other grids (e.g. United States, British Columbia, and Saskatchewan)
- Demand side management, e.g. load shedding at peak times when demand outstrips capacity
- Implementation of wind or solar electricity production over a wider geographic area to decrease variability
- Improved wind / solar forecasting tools
- Energy storage

Heat Production Characteristics

Heat is generated in Alberta from a number of sources including natural gas, coal, solar energy, cogeneration with electricity, biomass and geothermal energy. Heat often is produced near the point of use as compared to electricity which is more typically generated at large, utility-scale plants and then distributed to consumers through the electrical grid. Two important characteristics for delivering heat are the rate and temperature at which heat energy is supplied. For example, although there are extensive supplies of geothermal-based heat available in Alberta, the supply temperatures are too low to be used directly in most industrial applications. We discuss the pathways for delivering heat at greater length when discussing each energy individual resource.

Transportation Fuel Production Characteristics

Alberta's supply of transportation fuels is derived primarily from crude oil and bitumen. Developing sources of transportation fuel in Alberta include ethanol biofuel from wheat fermentation, biodiesel from oil seeds, compressed natural gas (CNG), liquefied natural gas (LNG) and electricity. Key characteristics of developing transportation fuels include:

- The ability to use the fuel in the existing transportation fuel supply network
- Whether the existing vehicle fleet can use the fuel or new types of vehicles will be required
- The energy density of the fuel
- The time needed to refuel the vehicle
- The environmental impact of the fuel.

Energy Pathways

In the Study, resources are converted to finished energy commodities (heat, electricity, and transportation fuels) via a number of pathways. Each pathway uses a specific technology mix to generate the commodity. As each resource is discussed, the pathways are clearly defined in terms of technology used, inputs and outputs and the scale of the technology. The metrics are resource- and pathway-specific. Not all resources will produce all three commodities. Figure ES.3 shows the general relationship between energy resources, pathways and the energy commodities.

Figure ES.3
Energy Resources, Pathways and Commodities

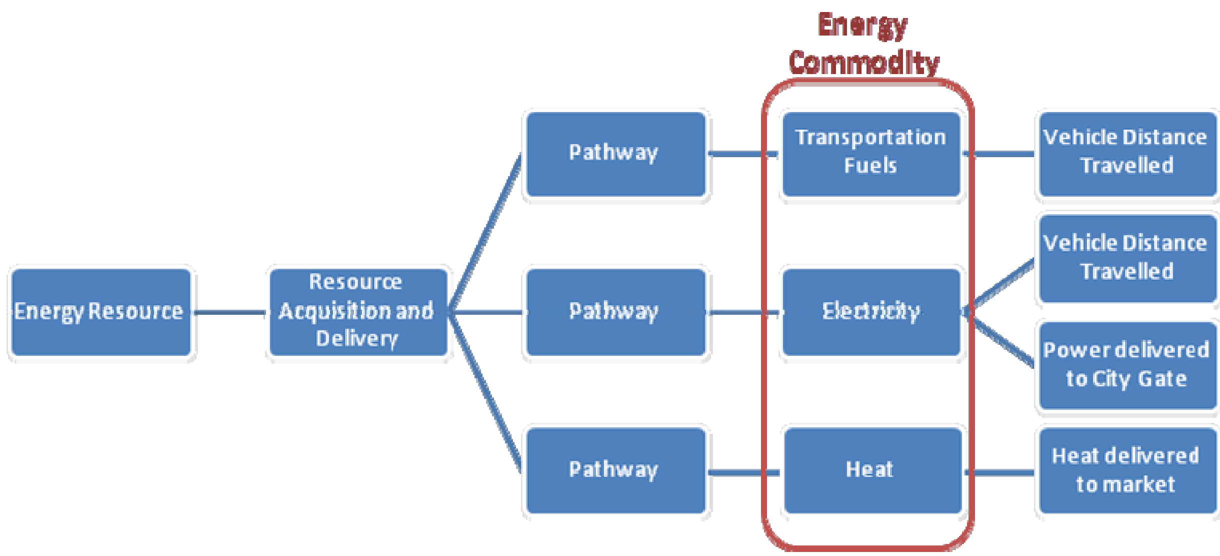


Table ES.1 shows the pathways and commodities considered in the Study.

Table ES.1
Energy Resources and Commodities

Energy Resources	Electricity	Heat	Transport Fuels
Hydrocarbon based			
Coal	√	√	NA
Oil (including bitumen)	√	√	√
Natural Gas	√	√	√
Biologically based			
Crops – food crops and non-food crops	√	√	√
Forestry products	√	√	√
Waste material from crops and forestry	√	√	√
Manure	√	√	√
Non-hydrocarbon, Non-Bio based			
Hydroelectric power	√	NA	NA
Wind	√	NA	NA
Solar energy for electricity	√	NA	NA
Solar energy for heating	√	√	NA
Geothermal energy	√	√	NA
Landfill gas	√	√	√
Municipal Solid Waste	√	√	√
Nuclear	√	√	NA
Electricity to Transport and Heat			
Transport	NA	NA	√
Heating	NA	√	NA

NA: Not applicable

Resource and Pathway Metrics Evaluation

The process of energy resource assessment involves various metrics which differ across resources. A reference set of metrics can aid in comparing the different energy resources and makes it easier to draw conclusions as to their utilization potential. Hence, it is important to define metrics that can effectively quantify the diverse resources and the impact of their conversion to energy commodities for end users.

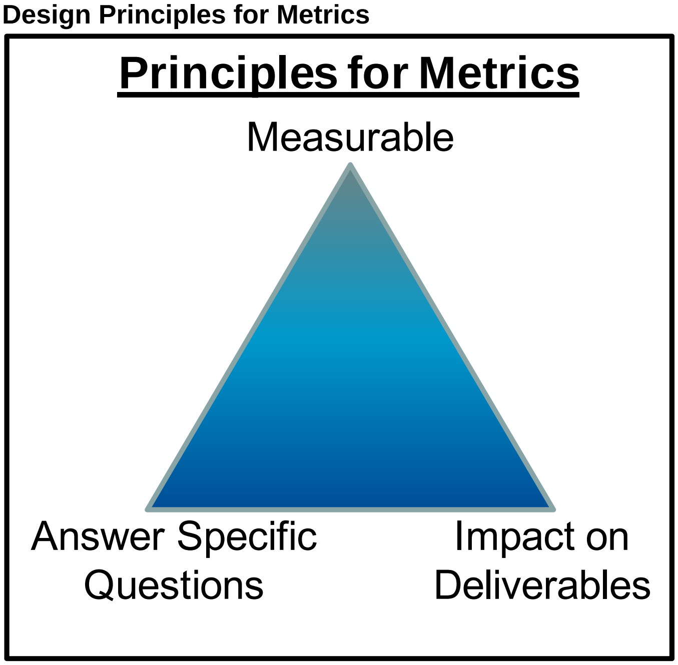
No single parameter defines an ideal energy resource because each energy resource requires an assessment of the total amount that is available, the potential to produce useable energy from the resource, and the impact of converting the primary resource into a commodity energy product. Assessment of energy resources involves using a number of different metrics which may have greater application to some resources than others. By using a wide range of metrics in our assessment we have attempted to present a balanced view of the wide range of energy resources that could be available to meet the energy needs of Alberta.

The challenge in applying these metrics was to appropriately define them and establish proper boundaries for assessment. For example, the energy available from canola produced in Alberta depends on the analysis boundaries. In one case, we could set the boundary to include the current canola crop that is produced in Alberta. Alternatively, we could set the boundary to include all canola that could be harvested in Alberta if all farmland was converted to canola production. Similarly, we can assess the wind energy resource in Alberta as the current wind energy capacity or as the potential capacity if wind turbines were installed in all the available areas with high wind.

With guidance from Alberta Energy and our Technical Steering Committee, we gave consideration to a few key principles for metrics as depicted in Figure ES.4:

- Is the metric applicable and measureable across various primary energy sources and commodity energy products?
- Does the metric answer specific questions about energy sources and products?
- Does the metric address Study deliverables appropriately?

Figure ES.4
Design Principles for Metrics



Study Conclusions

Metrics

The following overall conclusions can be drawn from the metrics developed in the Study.

Production and Capacity Metrics

1. **Remaining established reserve potential, primary source** – measures how much of the primary energy is available in reserve. It applies to stock energy sources such as coal, oil, natural gas but does not apply to flow resources such as wind, solar, or biomass.

   Alberta has abundant established reserves of bitumen and coal, much less of natural gas. However, the estimate of established reserve potential does not include unconventional oil and gas from coal bed methane, tight oil and gas and shale oil and gas. These unconventional resources have not yet been developed to the point where established reserves can be quantified. Based on geological observations and exploration to date there are indications of substantial unconventional resources to be developed in Alberta which would add to Alberta's established oil and gas endowment.

2. **Actual annual production, primary source** – measures how much of each primary source is produced in Alberta. It is an important benchmark for evaluating alternative sources of energy. (In the Study, production rates for stock based energy sources were kept at current rates and not increased.)

   Alberta produces more natural gas than any other energy resource. Alberta produces over 73% of Canada's marketable natural gas supply, 61-62% of the Canadian crude oil supply, and 42% of the Canadian coal.

3. **Current actual commodity produced and as a percent of Alberta consumption –** measures how much of each commodity energy (electricity, transport, and heat) is produced relative to Alberta's current demand. Surplus commodity energy can be exported.

   Alberta produces nearly 150% of its commodity energy demand for transportation fuels; what is not used in Alberta is exported to the other Canadian provinces and the US. Alberta produces nearly all of its electricity and all of its heat commodity energy.

   Electricity - Although capacity exists in Alberta to generate electricity from energy resources such as distributed solar photovoltaic, anaerobic digestion, and landfill gas, the amount of electrical generation capacity that these resources currently represent is small compared to the generation capacity from coal and natural gas. Electricity generation is dominated by coal in Alberta, with much of the rest of electricity from natural gas both from dedicated plants and as a byproduct of cogeneration of heat for oil sands energy extraction. Wind is a growing resource in Alberta but is still a small contributor.

Transportation fuels - Transportation fuels are produced from crude oil, including bitumen. There is virtually no production of transportation fuels from non-oil sources in Alberta.

Heat - Heat in Alberta is primarily produced from natural gas. Some of the natural gas based heat is for space heating but the majority of natural gas for heating is for high temperature heat for steam used in bitumen production, in bitumen upgrading, and refining. Some heat in Alberta is produced from biomass, some from waste streams from wood production, some from propane - mainly for residential heating, and there is a small amount of space heating from geothermal and distributed solar.

4. **Commodity production if all Alberta primary source is converted to commodity** – measures how much of each commodity energy could be produced if all the available primary energy were converted to the commodity energy. This metric assumes that if the entire primary energy source is used to produce commodity energy it is not available for other purposes, such as biomass for food, etc.

   Electricity – Over 700% of Alberta's current demand for electrical power could be generated from all the natural gas produced in Alberta. Nearly 800% of the electricity could be generated from the oil that is produced. About 700% of the electricity could be generated from wind if wind turbines were deployed over 25% of the potential land area in the white areas of the province with turbine spacing of 70 hectares per turbine. Installation of solar panels over all of the white space could supply many times the current demand for electrical power in Alberta – but this would mean that there would be no land for crop production. If solar farms were instead restricted to 10% of the white space, dedicated solar could easily supply ten times Alberta's electric power demand. However, because of the large summer-winter variation in daylight in Alberta, significant electrical storage and non-intermittent electricity generation backup would be needed for this option.

   Transportation fuels - Almost 700% of Alberta's demand for transportation fuel could be supplied if all the bitumen and conventional crude oil produced in the province were converted to transportation fuels. More than 550% of Alberta's transportation fuel demand could be met by the current production of natural gas – though there would be no natural gas for other purposes, and some electrical energy would be consumed in compressing the gas for on-board vehicle storage. Biofuels potentially could supply approximately 40% of current demand, but only if all land in Alberta were converted to crops that can be converted to biofuels.

Heat – All of the natural gas produced in Alberta could supply more than 250% of Alberta's current demand for heat – but this would eliminate export of natural gas to other provinces and the US. All of the oil produced in Alberta could potentially supply about 400% of Alberta's heat demand; if all of the coal produced annually in Alberta were used for heat, it could supply 40% of Alberta's current heat requirements. Landfill gas, anaerobic digestion, biomass combustion and MSW could supply only a small percentage of Alberta's heat requirement.

Energy Density Metrics

5. **Primary Source Energy Density (LHV) -** measures the energy content per volume or weight of an energy source. Higher energy density is desirable for energy sources that must be stored on board vehicles, for example:

   - Coal has energy density of 14 to 21 MJ/kg depending on the coal type (rank)
   - Natural gas has energy density of 47 MJ/kg (37 MJ/standard m^3). Compressed natural gas is sold by weight and has a volumetric energy density about ten times higher than natural gas at standard pressure. Liquefied natural gas has an energy density of 21 MJ/l Oil has energy density typically around 39-44 MJ/kg
   - Gasoline has energy density of around 42 MJ/kg (32 MJ/l)
   - Diesel fuel has energy density of 43 MJ/kg (36 MJ/l)
   - Ethanol has energy density of 27 MJ/kg (21 MJ/l)
   - Biodiesel as fatty acid methyl ester (FAME) has energy density of 38 MJ/kg (33 MJ/l)
   - Uranium fuel has an energy density of around 3,900 MJ/kg based on 3.2 wt% uranium in the fuel

Efficiency and Energy Consumption

6. **Energy consumption to produce a commodity energy product –** measures the energy consumed in producing the commodity energy from each primary resource. It includes the sum of external energy inputs plus energy losses due to inefficiencies.

   Electricity - It takes between 1.2 and 2 GJ of energy to produce one GJ of electricity from hydrocarbon based energy sources. It takes from about one GJ to about six GJ of energy to convert biomass, landfill gas or MSW to electricity. It takes 2.3 GJ of energy to produce 1 GJ of electricity from uranium. Our assumption has been that there is no energy expended to produce electric power from wind or solar, although in the case of wind, there may be measureable parasitic power consumption to operate the wind farm. We have not included the energy to make the wind turbine or the solar panel in the same manner that we have not included the energy to set up a coal mine, a bitumen upgrader, or an ethanol fermentation plant.

Transportation fuels – It takes around 0.1 GJ of natural gas to produce one GJ of transportation fuel and around 0.4 GJ of oil to produce one GJ of transportation fuel. It takes around one GJ of biomass to make one GJ of transportation fuel as ethanol and 0.2 GJ of biomass to make one GJ of biodiesel.

Heat – It takes from 0.2 to 0.3 GJ of hydrocarbon-based energy to make one GJ of heat. It takes 0.2 GJ of biomass in anaerobic digestion to make one GJ of heat and 0.3 GJ of landfill biomass to make one GJ of heat. It takes 0.2-0.7 GJ of biomass to make one GJ of heat from biomass combustion and MSW.

7. **Net Energy Ratio –** measures the net commodity energy that can be produced from a primary energy source, including all the energy needed for this conversion to commodity energy. It is defined as the energy in the commodity divided by the energy to convert the primary resource to the commodity plus the energy in the primary source.

   Electricity – The net energy ratio of electricity from coal, oil, nuclear, and anaerobic digestion is in the range of 0.2 GJ of commodity energy produced per GJ of primary energy plus the energy to convert the primary energy to commodity energy, including losses. It is around 0.3 for electricity from wind and from natural gas. This ratio is over 0.7 for electricity from hydro and around 0.1 for electricity from biomass combustion, and solar.

   Transportation fuel – The net energy to produce transportation fuels from oil is 0.6 and 0.8 for natural gas. For biofuels, the net energy ratio is 0.3 for biomass to ethanol and 0.7 for biomass to biodiesel.

   Heat – The net energy ratio to produce heat from hydrocarbon based energy sources ranges from 0.6 to 0.7. For biomass combustion it is 0.4; it is 0.5 from MSW, and 0.7 from anaerobic digestion.

8. **Distance Delivered –** measures how far a designated vehicle can travel per GJ of commodity energy. The designated personal use vehicles are measuring devices to enable comparisons. They are: a VW spark ignition engine for gasoline, ethanol, and natural gas; a VW diesel compression ignition engine for diesel and biodiesel; and a Nissan Leaf battery powered plug in electric vehicle for electricity.

   Electricity – Coal and oil deliver close to 500 km from each GJ of primary energy when converted to electricity Natural gas delivers 580 km from each GJ of primary energy. Nuclear delivers around 270 km per GJ; for wind the distance delivered is about 380 km per GJ. Biomass converted to electricity delivers between 200 and 350 km per GJ of commodity energy. Solar delivers about 100 km per GJ of primary energy when converted to electricity.

Transportation fuel – Both oil and natural gas deliver around 290 km per GJ of primary energy. Biomass delivers around 370 km/GJ as biodiesel from canola oil and around 170 km/GJ as ethanol produced via fermentation of biomass.

Environmental Metrics

9. **Greenhouse gas emissions** –estimates the GHG emissions for converting the primary energy to commodity energy, thereby providing a measure of the global warming potential of the path from primary energy source through delivery and use of the produced commodity energy.

   Electricity – Electricity from coal has a GHG emission intensity around 280 g CO_2e/MJ of electricity. Electricity from oil is around 230 g CO_2e/MJ of electricity and from natural gas it is around 125 g CO_2e/MJ. We assume that wind and solar have no GHG emissions associated with electricity production. Electricity from MSW, landfill, and anaerobic digestion have nil net GHG emissions. Hydro has a GHG footprint around 40 g CO_2e/MJ of electricity – primarily as a result of the land use impact, which includes the loss of CO_2 sequestration in biomass that is covered by the reservoir.

   Transportation – The well to wheels GHG emission intensity for converting oil to transportation fuels is on the order of 99 g CO_2e/MJ of transportation fuel – which includes the GHG emissions from oil production, transport, refining to products, and combustion of the fuel onboard the vehicle. It is 64 g CO_2e/MJ of natural gas. It is around 30 g CO_2e/MJ of biodiesel and 100 g CO_2e/MJ of ethanol. These assessments include the GHG land use impact of each fuel pathway.

   Heat – The GHG emission intensity of heat from natural gas, oil, and coal range from 80-120 g CO_2e/MJ of heat. We assume no net GHG emissions for heat from biomass, landfill gas and MSW.

10. **Land Use –** measures the land used in the process of extracting the resource and by the land occupied by the conversion facility.

    Electricity – the land use impact of electricity is only significant for hydro and utility based-solar, which uses solar panels installed on land rather than on rooftops. For hydro, the land use impact of electricity generation is around 5 ha/PJ of electricity. For utility based solar the land use impact is about 750 ha/PJ of electricity.

    Transportation fuel – land use for the production of transportation fuel via ethanol fermentation of grain is on the order of 45 ha/PJ of transport fuel. It is around 25 ha/PJ for biodiesel from canola. For gasoline and diesel from oil, the land use impact is 0.003 ha/PJ of transportation fuel.

Heat – the land use impact of generating heat from coal is on the order of 0.02 ha/PJ, which is about the same as for biomass combustion. It is less than 0.002 ha/PJ for oil and even less for natural gas.

11. Water Use - measures the amount of water to produce a commodity energy

Water use is significant for hydro, over 40 m^3/PJ for electricity generation, mainly the result of evaporation from the reservoir. For the other energy sources, water use is between 0.1 m^3/PJ of electricity (wind) to nearly 0.6 m^3/PJ of electricity for coal and 0.5 m^3/PJ for nuclear.

12. Biodiversity – is an important and complex issue in resource project development.

Biodiversity is a measure of variability in a given ecosystem but is difficult to quantify as a metric similar to the other metrics that we have used in the Study because biodiversity attributes are highly location- and development-specific. In addition, development projects that could negatively affect biodiversity may be ameliorated through sustainability action plans specific to the project, such as species conservation plans. We did not include biodiversity assessment as a quantitative metric in this Study.

Observations

Examining energy in an Alberta context requires understanding the particular characteristics of each energy sector as well as the dynamics of the rapidly changing energy environment. Three characteristics of the energy sector in Alberta we believe are important in understanding the nature of the energy in Alberta.

- **First:** Alberta is a province with relatively low population density, a high degree of industrialization, and a resource-intensive economy. Much of the energy in Alberta supplies industrial demand, especially in oil sands production, and there is continued high growth in industrial demand for energy, especially heat. Energy demand in the Province is dominated by the need for high intensity, high quality sources of heat to support the oil sands industry, which is export oriented. Growth in demand for energy for the oil sands area is greater than in other sectors of the economy, which means that the demand for high temperature sources of heat will continue to outstrip demand for relatively low temperature heat for space heating.

  While Alberta's geothermal resources are abundant, they are relatively low temperature and not suitable to provide direct high temperature heat for in situ bitumen production or process heat for natural gas clean up, bitumen upgrading, oil refining or petrochemical production. High temperature sources of heat can be supplied by direct combustion of fuels – especially natural gas - or on a longer time horizon, potentially from nuclear.

- **Second:** Alberta has abundant and diverse energy resources. Much of the oil and natural gas-based energy is exported to other provinces and to the US. The availability of hydrocarbon based resources such as coal and bitumen far outstrip provincial demand. The potential large reserves of unconventional gas and oil will likely continue to position Alberta as an export oriented energy industry.

  The oil refining infrastructure is more than sufficient to meet provincial demand for transportation fuels from oil. In the electricity sector, significant capital investments will be required over the coming decades to either replace coal-fired power plants or add carbon capture and storage (CCS) to coal-fired plants in order to meet federal GHG requirements. In addition, investment will be needed to improve the electrical supply grid to meet the requirements of a stable electricity supply as more intermittent sources such as wind and distributed solar supply the grid, and to meet the demand for electricity from the continued growth in Alberta's Industrial Heartland.

  Alberta is essentially an energy island as a result of its relatively small internal market and the geographic isolation of the Province. Unlocking the full potential of its resources, will mean that Alberta must continue to look to markets outside of the Province while overcoming infrastructure and regulatory hurdles to energy exports and electricity import.

- **Third:** As Alberta, Canada and the global economy move toward a more carbon constrained environment, Alberta is committed to reducing carbon emissions and lowering carbon intensity. These goals can be difficult to achieve in a region with a high degree of industrialization and a burgeoning fossil fuels industry and relative geographic isolation from other markets – especially electricity markets.

  To meet the environmental constraints, Alberta must develop energy resources that can meet the demands of its industrial market while also lowering the carbon intensity and other environmental impacts of its energy supply. In particular, we see this in the electrical sector in which federal GHG legislation has mandated that Alberta reduce emissions from coal fired power plants by either implementing carbon capture and storage (CCS) or by using lower-carbon-intensity sources of electrical power.
  We expect this shift in electricity generation not to be monolithic in nature, but rather a move toward a more diversified electric power supply portfolio. The nature of this portfolio likely will reflect the trade-offs between the different power supply pathways.

For example, wind power provides electricity with very low GHG emissions but because it is variable in nature it will require back-up from other dispatchable sources of electricity, which are often stock-based sources of electric power such as natural gas, coal, or possibly nuclear, or on a longer time horizon may even include geothermal or large-scale energy storage.

We foresee natural gas as playing a much larger role in electric power generation due to its lower carbon footprint and high capacity factor. On the supply side, greater development of unconventional natural gas reserves will enable Alberta to meet its increased demand for low-GHG-emission, dispatchable electricity supply as well as the increased demand for high temperature energy to enable growth in oil sands production.

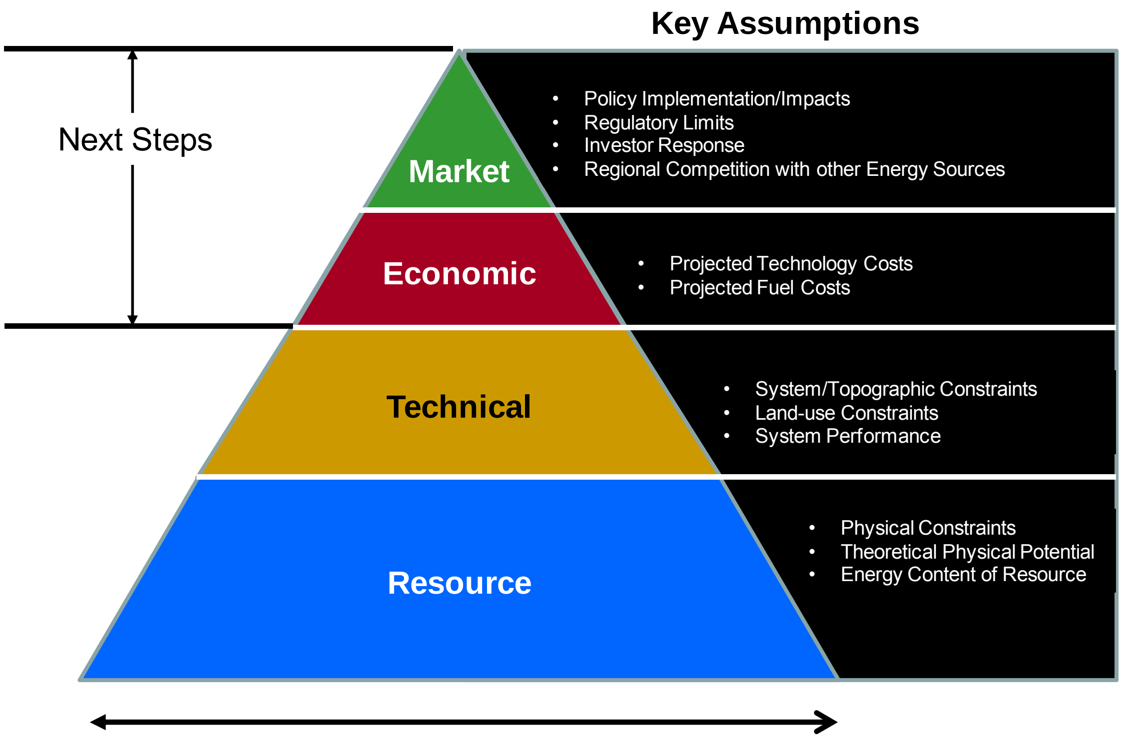
The changing nature of the electrical power supply portfolio also will require changes to the electrical grid in Alberta so that the increasingly diverse and variable sources of electric power can be accommodated without compromising the supply of stable high quality electric power.

Next Steps

The focus of this Study has been on understanding the resources and technical potential and constraints of the energy supply in Alberta without taking into account economics or public policy. As we have analyzed the potential feasibility of energy supply to Alberta we have ignored the fact that some of the energy pathways considered are not currently implemented or have not been broadly implemented because they are not economically feasible. In addition, certain technologies may not be implemented or may be shut down for policy reasons.

It is clear that any analysis of Alberta's energy potential is incomplete without including an assessment of economics and public policy. To do so we must shift our focus to the upper two sections of the energy pyramid described earlier – the economic and market factors that will provide further understanding about the constraints and direction of energy development and deployment in Alberta. (See Figure ES.5)

Figure ES.5
Pyramid of Stages for Energy Supply Evaluation



Source: National Renewable Energy Laboratory (NREL), 2012

Economics and Regulations

Several examples of economic and regulatory issues that are likely to affect energy resource development in Alberta include the following:

- Hydroelectric power – Two identified major dam sites in Alberta have not moved forward in the development process. Hydroelectric power is attractive because of its low greenhouse gas emissions and because it is dispatchable. However, hydro projects have languished due to environmental opposition to land use changes inherent to reservoir-based hydroelectric development and difficulties in financing major capital investment in power production that will not pay out for many years.
- Nuclear power - A potential site for a nuclear power plant near Edmonton has been considered in the past. There has also been support for nuclear power to provide low carbon intensity energy for SAGD sites. However, none of these projects were implemented for multiple reasons including economics, project financing, difficulty in finding appropriate sites, and local opposition.

Providing a complete picture of energy potential in Alberta, will require fully describing the economics and costs of developing each potential energy resource. It will also require fully assessing the regulatory environment in Alberta as well as at the federal and international level. The energy sector crosses both inter-provincial and international borders and regulatory developments outside of Alberta and Canada will continue to affect the Alberta energy sector. Resource potential and the ability to develop energy commodity production projects should be analyzed using scenarios and risk assessment tools to understand how future regulations may affect each source.

The next steps in understanding the potential energy supply in an Alberta context must include an economic and market analysis of resources and pathways for energy in Alberta as well as an analysis of potential provincial, federal and international regulations and export opportunities and infrastructure needs.

Energy Transport

Alberta has abundant and diverse reserves of energy in existing, identified hydrocarbon-based resources and potential non-hydrocarbon-based resources such as wind and solar. With the magnitude of hydrocarbon-based resources in Alberta such as coal and bitumen far outstripping provincial demand and its geographic isolation and land locked position, Alberta is essentially an island that is rich in energy resources. Unlocking the full potential of its resources will mean overcoming hurdles to energy exports and limits on GHG emissions from energy sources.

Overcoming the barriers to energy development will require oil and gas routes with access to markets south, east and west of Alberta. Pipeline projects have been proposed and steps are being taken to overcome regulatory hurdles. Rail routes for oil are being expanded. Some of the barriers to bitumen export via pipeline result from the need to overcome viscosity and density limits imposed by pipeline shippers, which requires either dilution of bitumen with a lower boiling material or conversion to a bottomless synthetic crude oil. New technologies being considered to overcome bitumen shipping infrastructure limits include partial upgrading of bitumen and shipment of hot undiluted or less diluted bitumen by rail. A comprehensive identification of scenarios and risk assessment of potential systems for bitumen export will help identify potential limitations to the development of the bitumen resource in Alberta.

Increased production of refined products from Alberta oil and bitumen resources could be another route to add value. However, this option will require increased export of refined products from the Province that heretofore has not been economically attractive and will likely require new transport infrastructure. Exploitation of new sources of natural gas could also be attractive, if there were ways to bring this material to world markets, which will likely include new pipelines and LNG facilities at coastal locations.

Another example of infrastructure to meet the diverse portfolio of future energy for Alberta will be to increase integration of the regional electrical grid system with Saskatchewan, British Columbia and the US power grids which may enable greater exploitation of Alberta's plentiful supply of wind.

Technology Development

A key observation from this Study is that the supply of energy in Alberta is rich and varied Different energy resources and pathways provide different benefits and challenges. As a result of new regulations limiting CO_2 emissions from electricity generation, Alberta will need to change from a highly coal-based electricity supply to one that has lower GHG emission intensity. A second observation is that Alberta has abundant supply of hydrocarbon-based energy sources. The Province is a significant exporter of natural gas, bitumen-based oil, and conventional oil and Alberta has large reserves of coal. A third observation is that Alberta has significant potential for wind-based and solar-based electricity supply, but that managing the intermittent and variable nature of these energy sources is likely to limit their deployment. A fourth observation is that Alberta is not likely to meet its energy needs with bio-based energy or with hydro-based electricity. New hydroelectric generation capacity is expensive with significant land impact. Bio-based energy from crops or wood is too small of a resource to have much impact on Alberta's total energy needs. Further, diverting land to energy use will affect food production. Using landfill gas, gas from anaerobic digestion and MSW as energy sources makes sense to reduce the impact of waste disposal, but these resources are too small to supply much energy for Alberta. Geothermal-based energy suffers from underground temperatures that are low. Nuclear energy is limited because of cost, perceptions about safety, and waste disposal/storage issues.

Fully developing the potential of these varied resources within economic, policy and regulatory constraints will require technology developments and innovations. In particular, we see the several areas of technology development as key to the successful future development of Alberta's resources.

Unconventional Hydrocarbon Resource Development

Reducing the GHG emission intensity of electricity production with dispatchable power generation, providing backup for wind and solar power, and additional energy for bitumen extraction will require more natural gas. Significant potential exists to produce light oil and natural gas from shale formations, in the same manner as has been done in the Barnett, Haynesville, Bakken, Eagle Ford and Marcellus formations in the US. Adoption of new exploration and development technologies and new drilling technologies will enable Alberta to unlock the potential for tight oil and gas and shale oil and gas. These technologies have the potential to significantly increase Alberta's established reserves in both natural gas and oil and provide future supply for both energy export and use of natural gas for electricity generation and in situ bitumen production in the province.

Electricity Storage and Enhanced Grid Technology

Deployment of low carbon electricity sources such as wind and distributed solar photovoltaics is limited by the intermittent and variable nature of these sources. While natural gas fired power plants can provide backup when these resources are not producing electricity, energy storage provides a way to capture the surplus energy from wind and solar. Development and adoption of energy storage and enhanced grid technologies will enable higher penetration of these technologies while maintaining grid stability and delivering low GHG intensity electricity to meet demand.

Geothermal Technology

Alberta's geothermal resources are at temperatures too low to directly generate high temperature heat. Low temperature heat could be used for space heating based on heat pumps. However, because of its climate, the demand for air conditioning is low, which reduces the economic incentive for geothermal space heating/cooling in Alberta. Also, the current high carbon intensity electric grid in Alberta means that geothermal heat pumps do not have a significant GHG emissions benefit over natural gas based space heating. Improving the efficiency of geothermal energy capture could further the use of this low level source of heat. Reducing the carbon intensity of the electrical grid could provide incentive for more widespread adoption of geothermal technology. Improvements in drilling technology to recover tight oil and gas will lead to improvements in capturing geothermal heat.

Carbon Capture and Storage

To date, the economics of CCS have not been conducive to capturing and disposing of CO_2 resulting from energy use. If storage technology were proven to be robust and the economics for CCS could be improved sufficiently, coal might become an attractive source of electric power.

Nuclear Power

Reducing the cost of nuclear power plants may make this energy source more attractive. Smaller, modular plants could better match Alberta's energy needs. Robust safety and security systems and waste management that overcome society's objections to nuclear power could further enable deployment of this very low GHG emissions energy source.

Demand Reduction

Critical to managing energy in Alberta is the continued drive to reduce provincial energy intensity. Technologies to reduce demand through efficiency improvements can improve energy intensity in all sectors. In the residential and commercial sector, technology improvements can reduce energy use by the adoption of more efficient lighting, appliances, and space heating. In transportation, engine efficiency improvement and technologies to reduce tire resistance and vehicle weight will decrease fuel demand on a kilometer-driven basis. In the industrial sector, technologies to reduce steam use for in situ bitumen production, to improve heat integration and to use lower carbon fuels will decrease energy demand and lower carbon emissions.

Timing

We opine that within the twenty-year time horizon of the Study, many incremental improvements that we have discussed throughout this report could take place in all sectors of Alberta's energy industry. Technology breakthroughs may occur at any time. However, the probability of success in major new technology development is likely much lower than for incremental improvements to known technology. An example would be the continuing struggle to commercialize biofuels based on cellulose conversion by novel organisms versus continuing improvement in conventional sugar fermentation technology. Thus in the time horizon of the Study, we might not expect to see a large number of energy conversion breakthroughs.

We have attempted in this Study to examine energy within an Alberta context to better understand the particular characteristics of each energy resource that now or in the future could supply the energy needs of Alberta and its energy export market. Many of these energy sources are undergoing rapid change. New sources are being developed. Some sources may be curtailed without new technologies to reduce their societal impact. Regulations on energy use and especially its environmental impact will undoubtedly change Alberta's energy portfolio. While we neither addressed the economics of energy production nor the rate of new energy resource deployment in this Study, we well know that the next step in understanding Alberta's energy endowment will be to go beyond the boundaries of this Study, to next address the economic and market issues that affect energy.

Section 1.

Introduction

Introduction

Jacobs Consultancy Canada Inc. (Jacobs Consultancy) was contracted by the Alberta Government (the Alberta Department of Energy) in 2012 to carry out an *Energy Potential and Metrics Study—An Alberta Context* (the "Study"). Jacobs Consultancy and the Alberta Department of Energy formed the Study Team, which was guided by a Technical Steering Committee who reviewed the work and offered comments and direction.

The Study is intended for a broad audience representing environmental interests, the energy industry, academia, and groups involved in setting government regulations and policy.

Study Objectives

The Study is a first-order engineering assessment of Alberta's energy resources that facilitates an understanding of Alberta's energy resource potential based on assessing all resources in a comprehensive and consistent manner. Key to this analysis is the overall material and energy balance for each Alberta-based primary energy resource that highlights the potential of each resource to supply commodity energy products. In addition the use of a broad span of consistent metrics to assess each resource provides a thorough analysis of the issues regarding resource potential. The Study followed a methodical, sequential analysis for each energy resource.

The scope of the Study was to:

1. Identify the gross resource base for primary energy resources in Alberta: natural gas, coal, oil, biofuels, biomass, hydroelectric power, landfill gas, municipal solid waste, solar energy, geothermal energy, wind power, and nuclear energy.
2. Define the potential of these energy resources for commodity end use such as energy to produce electricity, energy required for heating, and energy as fuel sources for transportation.
3. Identify the potential of each primary energy resource through a technical assessment and identify any associated technical attributes that may be considered barriers to the development of these resources.
4. Address the various energy pathways through a series of metrics reflecting material and energy balance determinations. This results in more certainty in the resource input and conversion medium requirements, as well as the energy yield, associated process waste, and environmental impact.

5. Provide current resource potential estimates for each energy commodity, and comment on how, with technology improvements, these estimates may change over the next twenty years.
6. Provide well-documented references based on publicly available sources for all data.
7. Clearly show all assumptions and calculation methodologies.

Study Methodology

There are a number of steps we took in executing the Study:

1. Initiation:
   We completed a literature review of public and in-house sources. For each identified energy source (e.g. oil, natural gas, coal, biomass, wind, etc.), we generated a preliminary estimate of the:

   - Initial in-place resources
   - Potential pathways to commodity energy products
   - Proven reserve or capability and future development potential

   We proposed metrics and boundaries for the project.

2. Kick-Off Meeting:
   At the kick off meeting, the Research and Technology Branch of Alberta Energy, the Technical Steering Committee, and Jacobs reviewed the key factors in the Study including:

   - A comprehensive list of energy resources to be evaluated in the project; e.g. natural gas, coal, etc.
   - The preliminary development of energy pathways
   - Data sources
   - Design basis and boundaries
   - Proposed metrics
   - Proposed assessment approach for the project

- Development of future scenarios to be used in the evaluation of future energy resources – Business as Usual, Incremental Technology Improvements, and Breakthrough Technology Improvements.

3. Design Basis / Identify Gross Resources and Quantification:
The first phase of the project was to identify and quantify primary resources for those energy sources agreed upon in the Kick-Off meeting. We used publicly available data, in-house resources and data from third parties to quantify the gross resource base for each selected resource in the current timeframe.

4. Reconciliation of Data Among Sources:
Reconciliation between source documents for each energy source. The data generated in the design basis were reviewed from a first-principles approach to reconcile any conflicting data.

5. Define End Users:
We identified the end-uses for each energy source focusing on commodity energy products agreed upon during the Kick-Off meeting, namely, electric power, heat and transportation fuels. We did not consider petrochemical and chemical end uses for primary energy in the analysis.

6. Pathway Development:
We identified the most likely technical pathways to bring the resource to the end users. We evaluated all energy sources for their potential to generate electricity. We evaluated the appropriate energy sources for their potential to generate heat and to produce transportation fuels.

7. Technical Assessment:
Using first principle engineering assessments and in-house knowledge, we assessed the technical feasibility of each energy pathway and its potential for technical improvement. The cost of the pathway was not part of the assessment. The assessment was completed by evaluating the key metrics for each resource.

8. Metrics Assessment
Based on the assessment of reserves, the end-use, and the technical assessment of each resource pathway, the selected metrics were calculated and compared.

9. Barriers and Opportunities for Development
   Using the technical assessment, we analyzed the potential barriers and opportunities for further technical developments of each resource and the impact of these developments on the potential resource base. The analysis considered a twenty year timeframe.

10. Review Meetings
    A number of meetings were held to review progress with the Research and Technology Branch and the Technical Steering Committee. We incorporated recommendations into the Study as the work progressed.

11. Study Final Report
    In consultation with the Research and Technology Branch and the Technical Steering Committee we prepared a final report (this report) for the Study. We anticipate discussion of the Study with a broad Stakeholder Group, and that the final report will be distributed as required by the Research and Technology Branch and the Technical Steering Committee.

Technical Steering Committee

The Technical Steering Committee met with the Study Team on a regular basis. They helped set the basis for the Study. They provided technical information in their respective areas of expertise, and reviewed project progress and technical results. Meetings were held in Calgary and by teleconference/webconference. Technical Steering Committee members came from industry, primarily in Alberta, academia, and government agencies in Canada, at both the federal and provincial level. Organizations participating in the Technical Steering Committee are listed in Table 1.1.

Table 1.1
Technical Steering Committee

Government of Canada
Natural Resources Canada (NRCAN)
Government of Alberta
Alberta Agriculture and Rural Development
Alberta Energy
Alberta Environment and Sustainable Resource Development
Consultants/Experts/Agencies
Alberta Innovates- Energy and Environmental Solutions
Alberta Innovates-Technology Futures
University of Alberta
University of Waterloo
Industry
Canadian Association of Petroleum Producers (CAPP)
Canadian Energy Research Institute (CERI)
Canadian Geothermal Energy Association (CanGEA)
Canadian Hydropower Association (CHA)
Canadian Nuclear Association (CNA)
Canadian Solar Industry Association (CanSIA)
Canadian Wind Energy Association (CanWEA)
General Electric
Imperial Oil
Hatch Canada
Sherritt Coal
Suncor Energy
Western Canada Biodiesel Association

Report Organization

This Study final report is organized into a number of sections:

- The Executive Summary provides a thumbnail sketch of the Study and its key findings.
- Section 1 is this introduction to the Study.
- Section 2 describes the current state of energy resources and energy development in Alberta today.

- Section 3 discusses key attributes in the successful development of primary energy sources, their conversion to commodity energy products and delivery of these commodities to consumers.
- Section 4 covers the development of metrics for the Study.
- Section 5 describes in detail the availability of each primary energy resource, pathways for its conversion to commodity energy products, and the metrics used to evaluate conversion of each primary resource to the appropriate energy commodity products.
- Section 6 compares metrics among the primary energy resources and conversion pathways.
- Section 7 addresses future scenarios and how incremental and breakthrough technology developments may affect the utilization of primary energy resources and the efficiency of primary resource conversion to commodity products.
- Section 8 summarizes the conclusions of the Study and the next steps in evaluating Alberta's energy potential.
- Section 109 provides detailed references used in the Study.

Energy and Alberta

Energy is foundational, a key input to our standard of living and way of life. As a result, energy resources and the social/political/economic structures they support are interdependent. They evolve together and change in response to market and economic conditions.

Figure 1.1 depicts the natural development of our understanding of energy resources. The base of the pyramid is the potential of the energy resource itself, given our understanding of its breadth, accessibility and any physical constraints. The second level of the pyramid depicts our understanding of the technical limitations found in exploiting the resource, such as land use and environmental limitations, ease of physical recovery and conversion of the resource to commodity energy products, and the efficiencies of the various steps along the energy pathway. The metrics developed in the Study describe each energy resource potential and the technical parameters governing its development and conversion to commodity products.

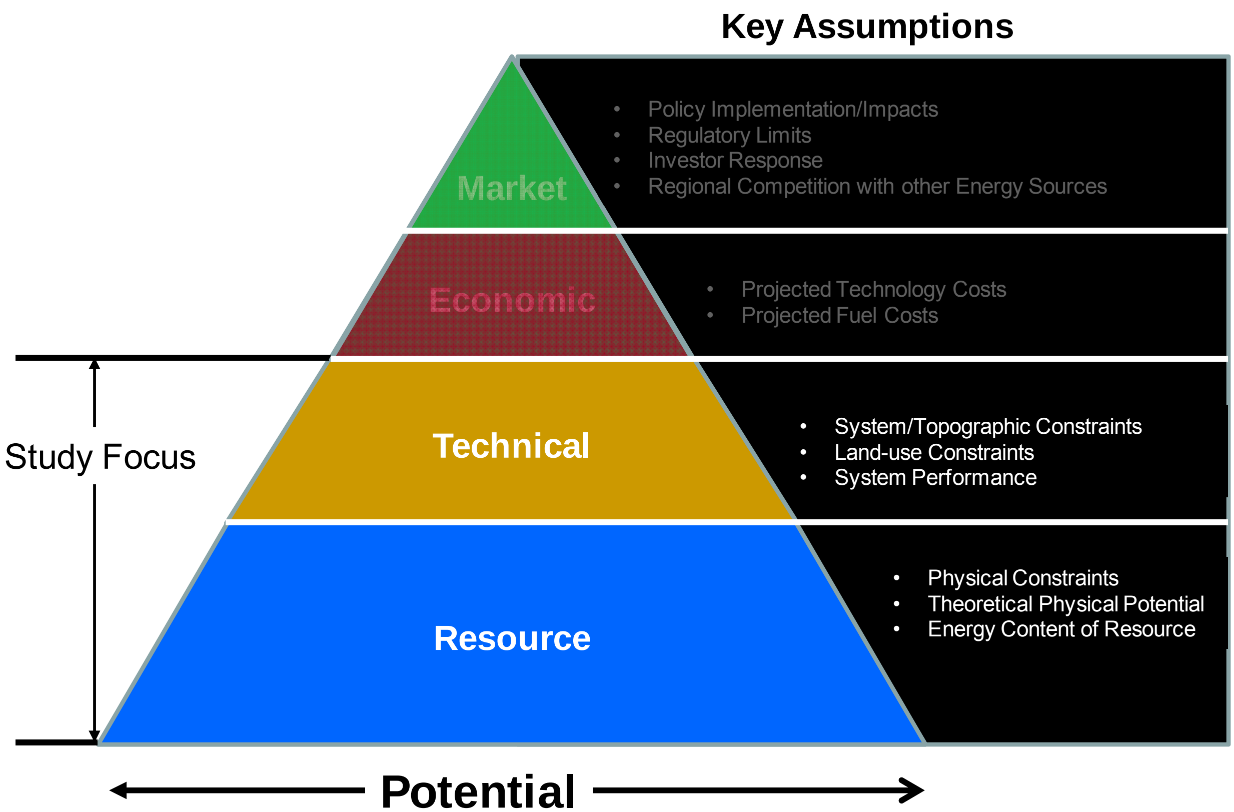
Given our understanding of the potential of a primary resource and the technical feasibility of its recovery and conversion, the third level of the pyramid shows us how capital and operating costs together with energy prices affect the delivery of energy to end users. Finally, at the top of the pyramid we see how various energy products compete with each other, subject to consumer preferences (of which one surely is price), government regulation and society's goals.

In the case of energy, limiting greenhouse gas emissions may be a social goal that is independent of consumer preferences or economics.

The Energy Potential and Metrics Study sets aside (for the moment) "economic conditions" to focus on a technical understanding of energy resources. The intent is an objective assessment of Alberta's resource endowment. As Alberta's energy landscape evolves (due to resource withdrawal, innovation, economic developments, regulatory policy etc.), the effects of actions taken persist long into the future, affecting the changing energy landscape of the Province. While economics can drive or limit resource development when market conditions are well defined, lack of understanding of resource potential or lack of technically feasible pathways to useful commodity energy products renders economic analysis moot. Moreover, a robust, long-term energy development policy for the Province will account for uncertainties in future economic forecasts and will be able to weather changing economic conditions.

Our first task is to understand how much energy potentially is available in Alberta, and that is the goal of this Study. A subsequent goal, not part of the Study, is to better understand the economics of energy and energy development.

Figure 1.1
Understanding the Development of Energy Resources



Source: National Renewable Energy Laboratory (NREL), 2012

Energy comes in many forms and is used in many ways. The use of energy resources involves decisions. For example, consumption of fossil fuels (natural gas, oil, and coal) contributes greenhouse gas (GHG) emissions to the atmosphere. Consumption of non-renewable energy sources raises potential risk of running out of these sources once the resources are depleted or become uneconomic to recover. Consumption of renewable fuels may be limited by their availability, may face technical constraints on total production, might compete with food production, or require greater use of marginal land and limited water supplies. Consumption of energy sources that are not produced locally raises concerns about energy security. Some energy sources are best suited to supply electricity. Others are better suited to supply transportation fuels. Some resources are available in high energy density on a consistent basis, others less so.

Energy consumption and its impact are very broad topics, not without controversy, and often fraught with a wide range of opinion and inconsistency. The Alberta Department of Energy engaged Jacobs Consultancy to perform this Study to enlighten this important policy area, to develop a rigorous understanding of the energy potential of resources available in Alberta and to promote a more consistent basis on which to compare energy resources.

How much energy is available from different fuel sources? How may we compare energy from renewable sources with energy from non-renewable sources? At what rate can energy be supplied from different sources? What is the net energy available from an energy source after subtracting off the energy needed for its production? What are the environmental impacts from delivering energy from various sources? These are complex questions that we address in the Study.

The report includes a comprehensive view of all major energy resources in Alberta and the pathways that are used to create basic energy commodities used in Alberta, namely, heat, electricity and transportation fuels. We use a broad spectrum of metrics to enable the reader to understand energy availability, energy density, and the environmental impact of a wide range of energy resources and pathways in Alberta. An important deliverable of the report is to provide a resource for energy literacy and to give the reader an improved perspective on Alberta's energy supply. The Study answers such questions as:

- How much energy is produced and consumed in Alberta and in what form?
- What resources are used in energy production?
- How do stock and flow resources differ?
- What happens when one energy source is substituted for another?
- What metrics can be used to compare energy sources and pathways?
- What are the limitations of energy resources in Alberta?
- What are the trade-offs between production and use of different energy commodities from different energy resources?

The Study provides a rigorous, engineering based approach to quantify the metrics used to compare energy sources. As each resource and pathway is discussed we provide detailed information about data sources, calculation methodologies, assumptions and system boundaries. This detail is intended to provide a high level of transparency and clarity for the reader.

The Study is intended for a broad audience. The focus on a qualitative assessment of metrics provides assistance to policy developers and planners, resource producers and developers, electrical power producers and grid operators, energy industry associations and academia.

Table 1.2 shows the pathways and commodities considered in the Study.

Table 1.2
Energy Resources and Commodities

Energy Resources	Electricity	Heat	Transport Fuels
Hydrocarbon based			
Coal	√	√	NA
Oil (including bitumen)	√	√	√
Natural Gas	√	√	√
Biologically based			
Crops – food crops and non-food crops	√	√	√
Forestry products	√	√	√
Waste material from crops and forestry	√	√	√
Manure	√	√	√
Non-hydrocarbon, Non-Bio based			
Hydroelectric power	√	NA	NA
Wind	√	NA	NA
Solar energy for electricity	√	NA	NA
Solar energy for heating	√	√	NA
Geothermal energy	√	√	NA
Landfill gas	√	√	√
Municipal Solid Waste	√	√	√
Nuclear	√	√	NA
Electricity to Transport and Heat			
Transport	NA	NA	√
Heating	NA	√	NA

NA: Not applicable

Section 2.

Current State of Energy in Alberta

Current State of Energy in Alberta

The Study evaluates a wide range of energy resources, hydrocarbon and non-hydrocarbon based, including:

Table 2.1
Primary Energy Resources

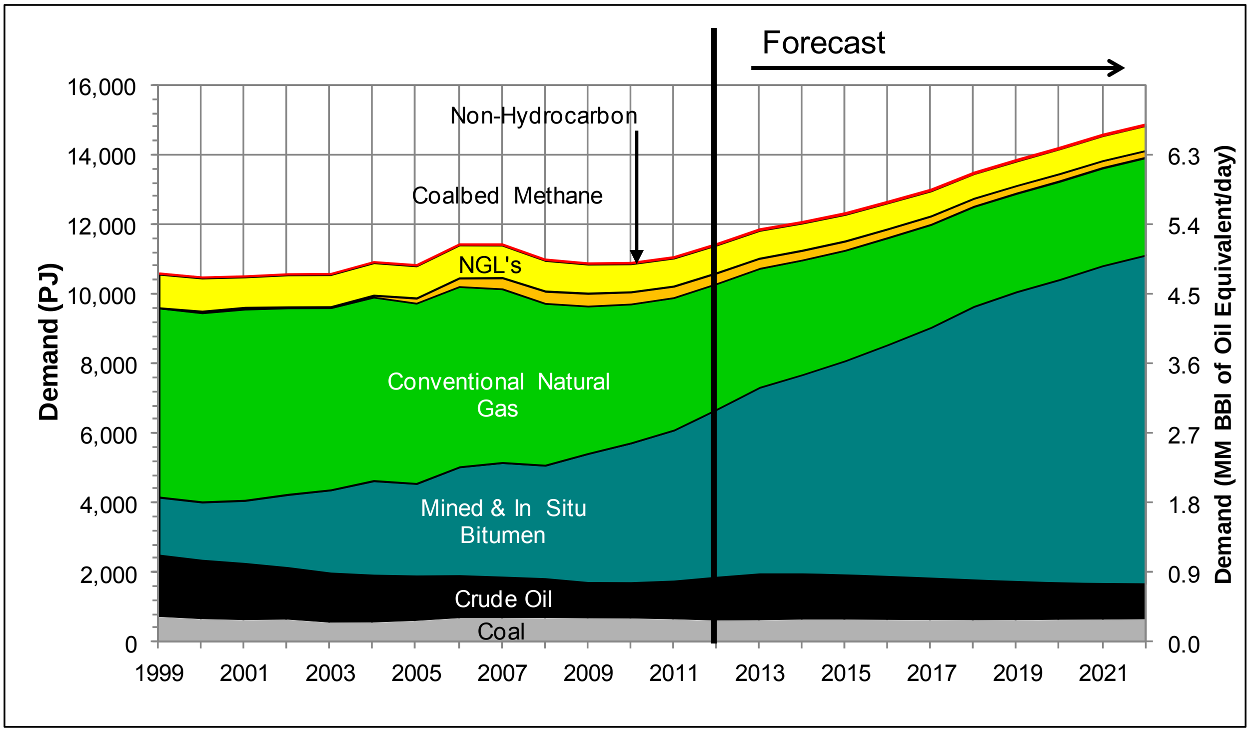
Hydrocarbon based	Non – hydrocarbon based
• Coal	• Hydroelectric power
• Oil	• Wind
• Natural gas	• Solar
	• Geothermal
	• Biomass
	• Uranium
	• Municipal solid waste

We consider pathways to convert the resources to three energy commodities: heat, electrical power, and transportation fuels. Each resource potentially can create more than one energy commodity. The following section provides an overview of current Alberta energy resource production, energy commodity production, and demand.

Alberta Energy Production

As shown in Figure 2.1, the majority of Alberta energy production currently comes from hydrocarbon based resources with a small fraction of supply from non-hydrocarbon energy resources. (Alberta Energy Regulator (ERCB), 2013) Mined and in situ bitumen is forecast to grow substantially in the short term. Conventional natural gas production is forecast to decline during the forecast period unless new sources of natural gas, such as from shale deposits, are developed.

Figure 2.1
Total Primary Energy Production in Alberta

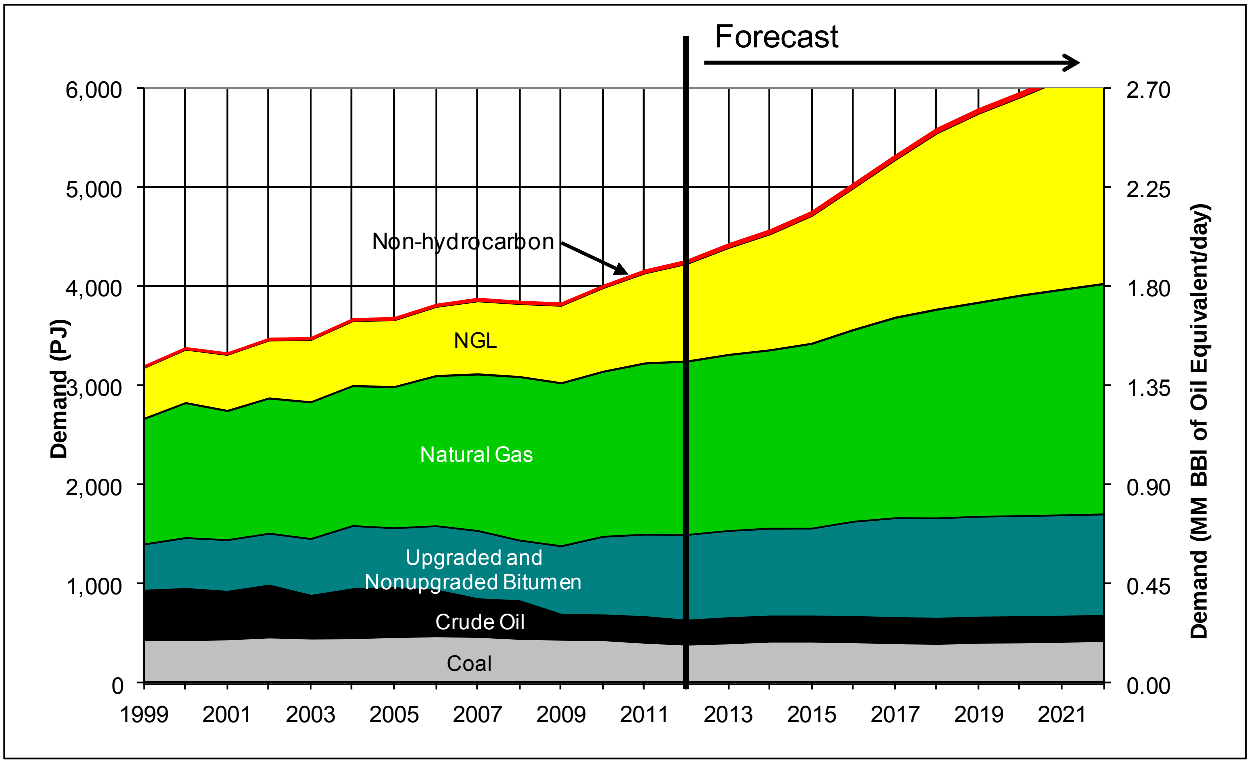


Source (ERCB, ST-98, 2013)

Primary Energy Demand – Alberta

As shown in Figure 2.2, energy demand in Alberta is dominated by natural gas and natural gas liquids. (ERCB, ST-98, 2013) Non-hydrocarbon sources such as hydroelectric power, wind and biomass fulfill only a small amount of Alberta's current total energy demand. The Alberta Energy Regulator does not forecast non-hydrocarbon resources to be a major contributors to the Alberta energy supply for the foreseeable future.

Figure 2.2
Primary Energy Demand in Alberta

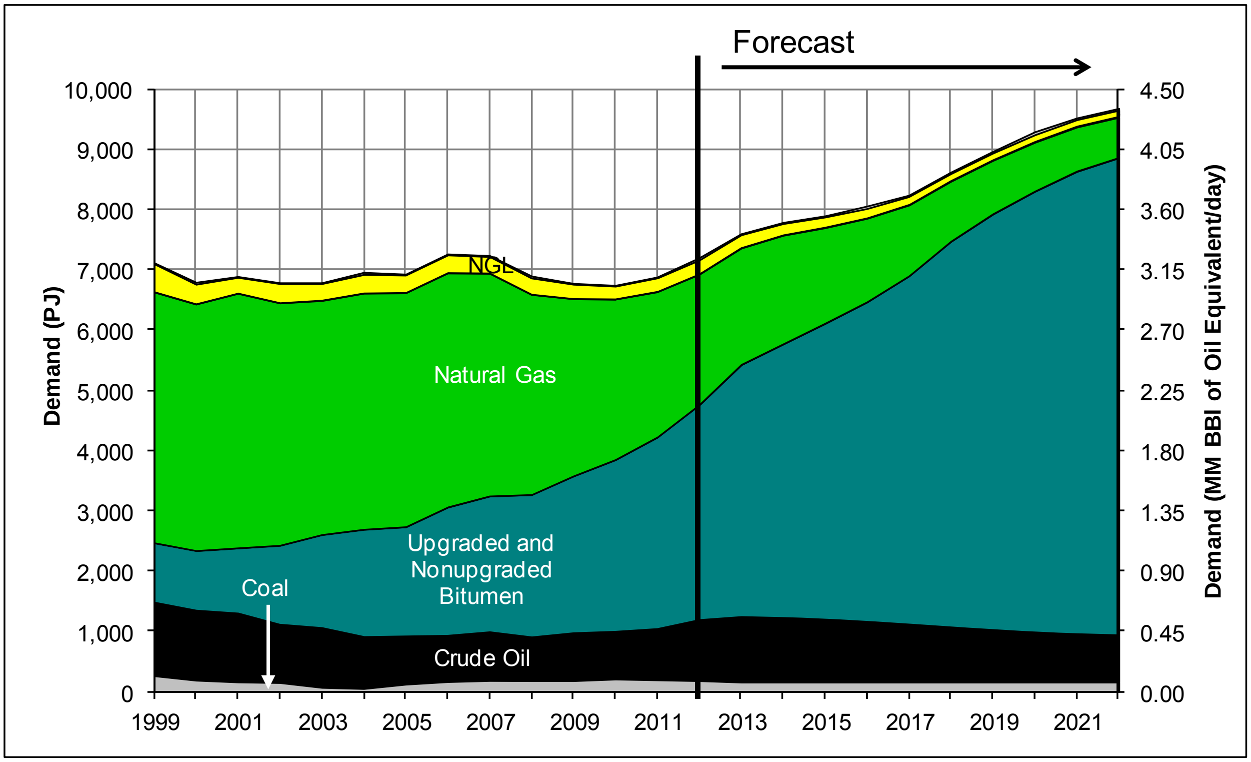


Source (ERCB, ST-98, 2013)

Primary Energy Removal – Alberta

In addition to provincial demand as shown in Figure 2.2, Alberta is a major energy exporter. Bitumen exports are forecast to increase as demand for crude oil from the US and other regions increases. (ERCB, ST-98, 2013) Natural gas exports are declining as a result of increased internal consumption and decreased US demand for Alberta natural gas as a result of extensive development and production of natural gas from shale deposits in the US. Should natural gas prices and demand increase, it is estimated that ample resources, such as shale deposits, are available in Alberta to supply this demand. (ERCB, ST-98, 2013) Figure 2.3 shows energy exports from Alberta.

Figure 2.3
Primary Energy Removals from Alberta



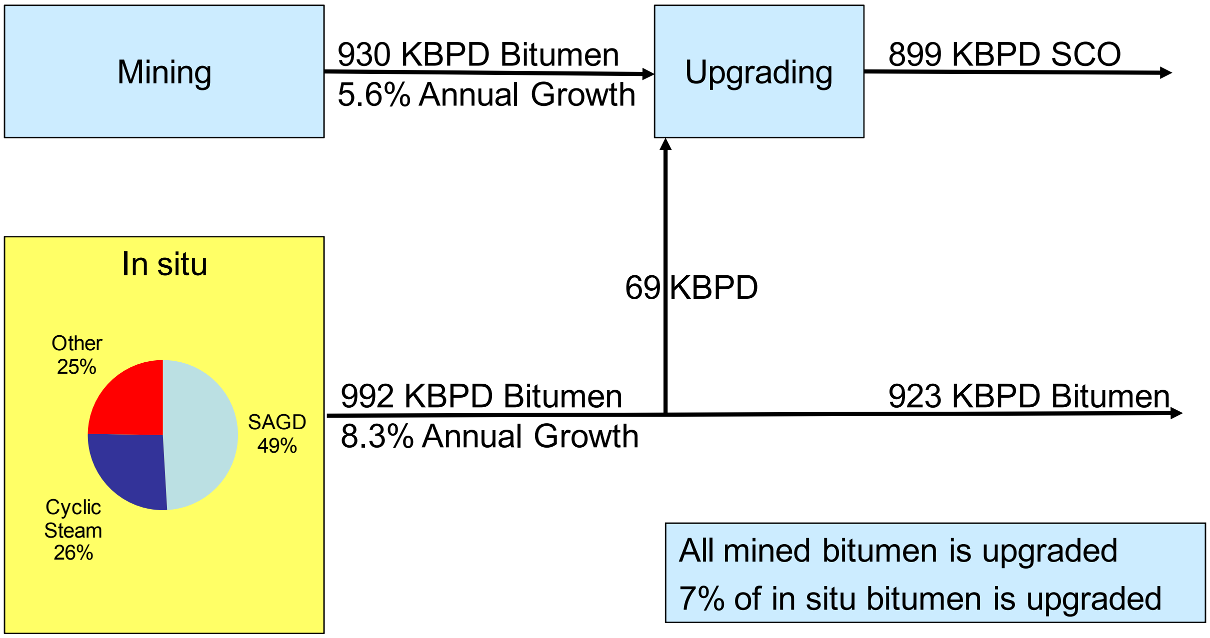
Source (ERCB, ST-98, 2013)

Bitumen Production and Disposition - Alberta

Alberta's primary source of crude oil is bitumen, which is produced by mining or by in situ methods. According to the Energy Resources Conservation Board (ERCB, now the Alberta Energy Regulator (AER)), all mined bitumen is upgraded to synthetic crude oil (SCO) in Alberta while only 7 % of in situ produced bitumen is upgraded to SCO. (ERCB, ST-98, 2013) The remaining in situ produced bitumen is diluted either with naphtha to become dil-bit or with SCO to become syn-bit.

Diluted bitumen is delivered to refineries that have appropriate refining capabilities to convert the heavy bitumen into refined products. Because SCO has no heavy bottoms material it can be processed in refineries without heavy bottoms conversion capabilities. Figure 2.4 shows the disposition of bitumen from in situ and mining production based on data from the ERCB. (ERCB, ST-98, 2013) In situ bitumen production consists of Cyclic Steam Stimulation (CSS), Steam Assisted Gravity and Drainage (SAGD), and non-thermal means (Other). The contribution of each of these production methods to in situ bitumen production also is shown in Figure 2.4.

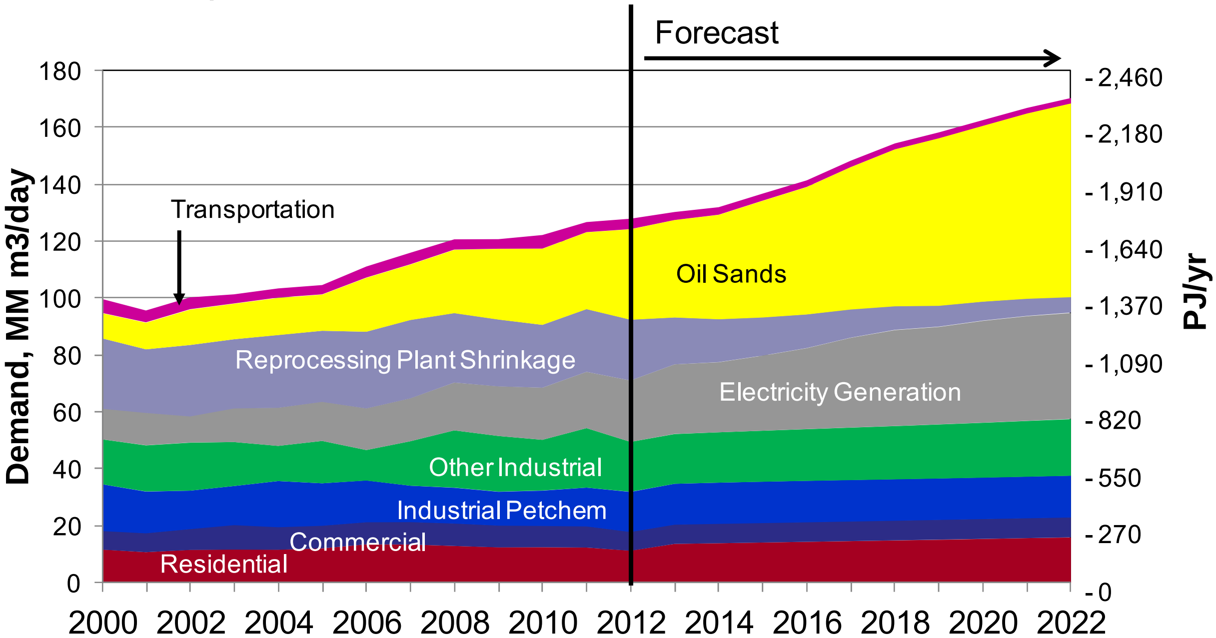
Figure 2.4
Alberta Bitumen Production and Disposition



Natural Gas Disposition – Alberta

Natural gas demand is broken down into four major sectors: residential and commercial heating, industrial demand including petrochemicals, electricity generation, and oil sands demand. Oil sands demand is driven by the consumption of natural gas in the production of heat for in situ bitumen production. Figure 2.5 shows the historical and forecast natural gas demand in Alberta by the major sectors. Most of the growth in natural gas demand in Alberta is to supply energy for production of bitumen from oil sands. (Alberta Energy Regulator (ERCB), 2013)

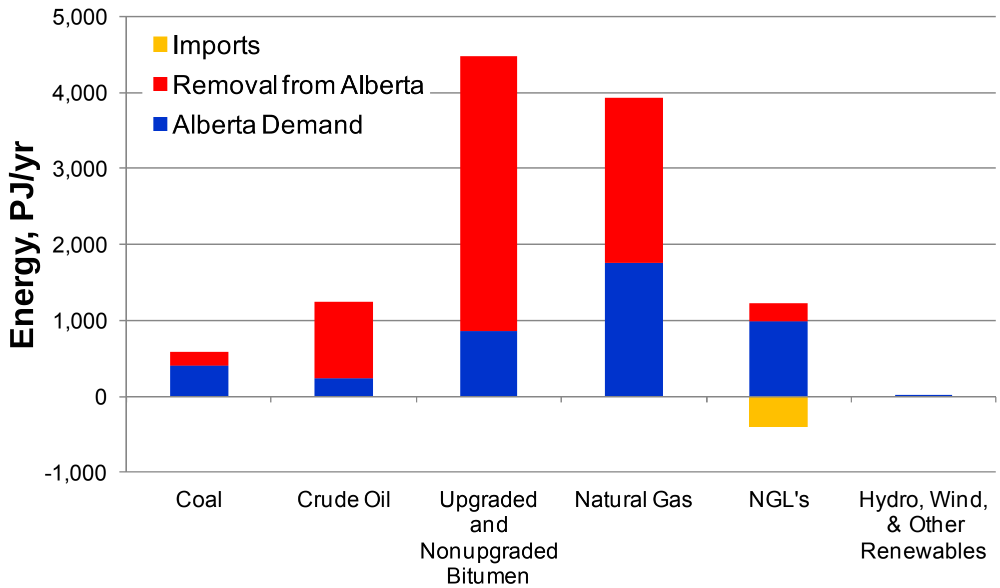
Figure 2.5
Natural Gas Disposition Alberta



Energy Disposition – Alberta

Figure 2.6 summarizes the disposition of energy resources in Alberta in 2012 and is based on data from the ERCB. (ERCB, ST-98, 2013) Alberta exported approximately 63 % of its total resource production in 2012, including 75% of bitumen produced and 55% of natural gas produced (not including natural gas liquids). There is some import of natural gas liquids to Alberta, primarily for use as diluent in bitumen transport.

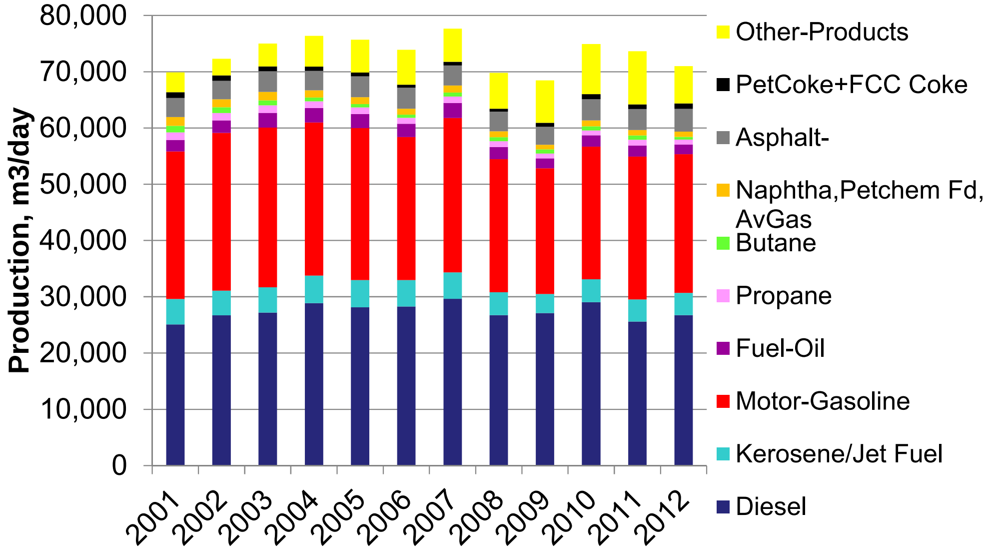
Figure 2.6
Energy Disposition - Alberta 2012 (ERCB, 2013)



Refined Products – Alberta

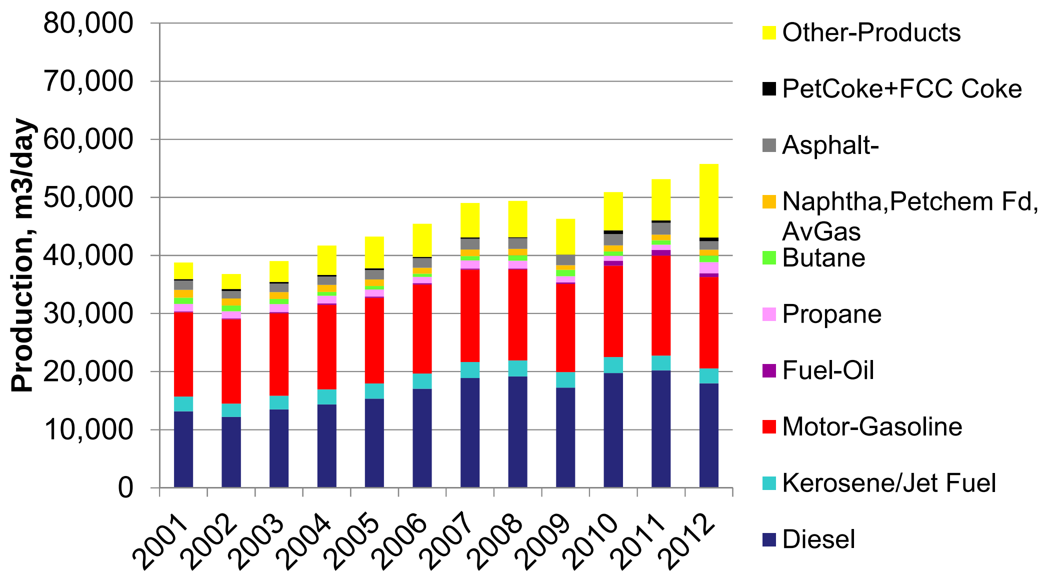
The total production of refined products in Alberta is shown in Figure 2.7; total demand for refined products is shown in Figure 2.8. Gasoline and diesel make up the largest volume of refined products, approximately 72% of total refinery output in 2012. Alberta's refineries export approximately 20% of their total production of refined products. Refined product volumes have been increasing steadily over the last decade. Canadian federal regulations require the use of 5% bioethanol and 2% biodiesel in the transportation fuel pool in Canada. Biofuel consumptions are not shown in Figure 2.7 or Figure 2.8. (Canada_Gazette, 2010) In the figures below, "Other Products," as defined by CanSim, include wax and candles, unfinished products, lube oils and greases. Unfinished products are the volume of material that is being processed in a refinery at any particular point in time that cannot be identified in end product terms. They also include imports or purchases of blending agents in inventory where the end product may not be known.

Figure 2.7
Alberta Refined Products Production



Source: (CanSim, Statistics of refined petroleum products, monthly (Cubic metres), Jan 1956 to Apr 2013, 2012)

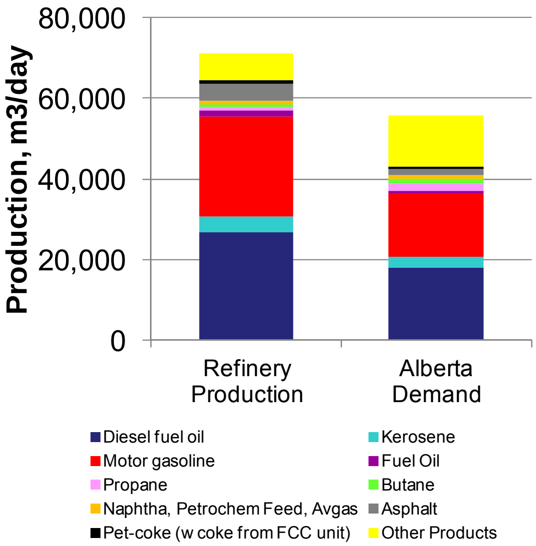
Figure 2.8
Alberta Refined Product Demand



Source: (CanSim, Statistics of refined petroleum products, monthly (Cubic metres), Jan 1956 to Apr 2013, 2012)

Figure 2.9 summarizes Alberta production and consumption of refined products in 2012 and highlights that Alberta produces more refined products than are consumed in the Province.

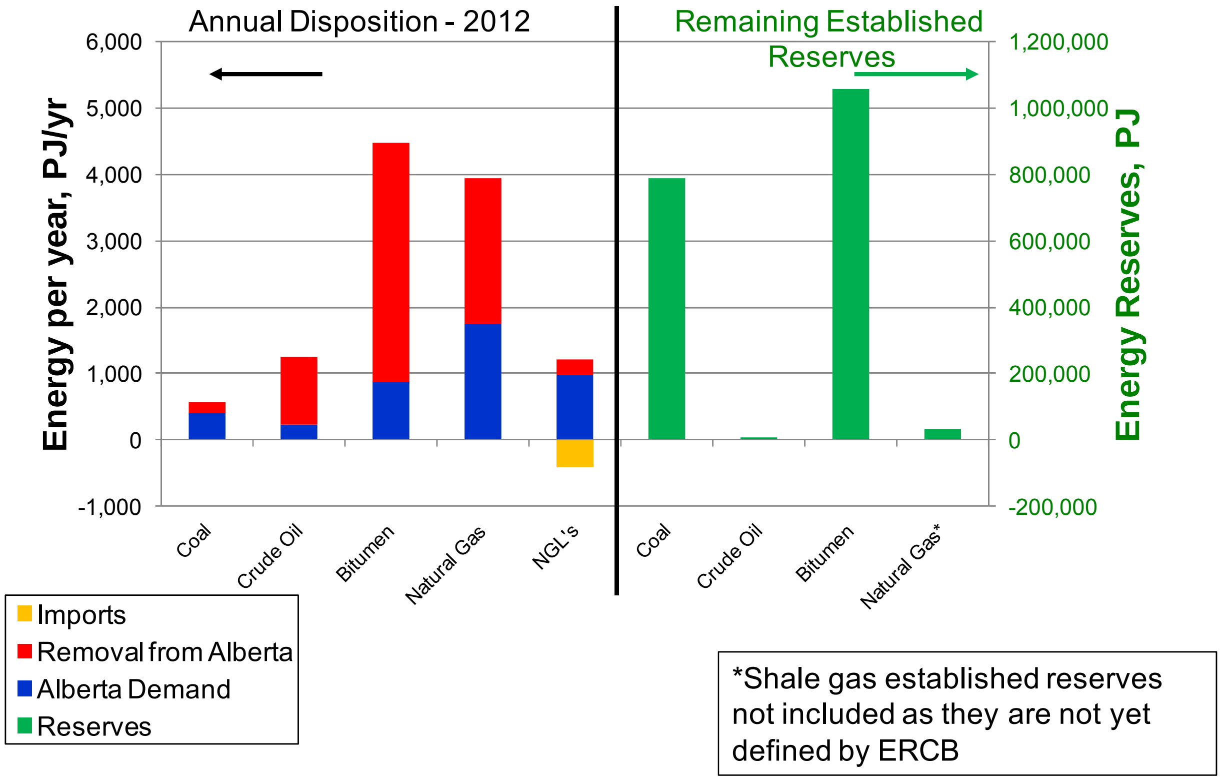
Figure 2.9
Refined Products Production and Demand Alberta 2012



Energy Reserves from Hydrocarbon Based Resources

Established reserves are defined by the ERCB as "those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty." (ERCB, ST-98, 2013) The right hand portion of Figure 2.10 shows Alberta's remaining established reserves for coal, crude oil, bitumen and natural gas. Alberta's oil and bitumen reserves are ranked third in the world (EIA, International Energy Statistics, Proved Reserves of Crude Oil, 2013). Canada is ranked 12th in the world for coal reserves. (EIA, International Energy Statistics, Total Recoverable Coal by Country, 2008)

Figure 2.10
Energy Reserves from Hydrocarbon Resources Alberta 2012, (ERCB, 2013)



Unconventional Reserves

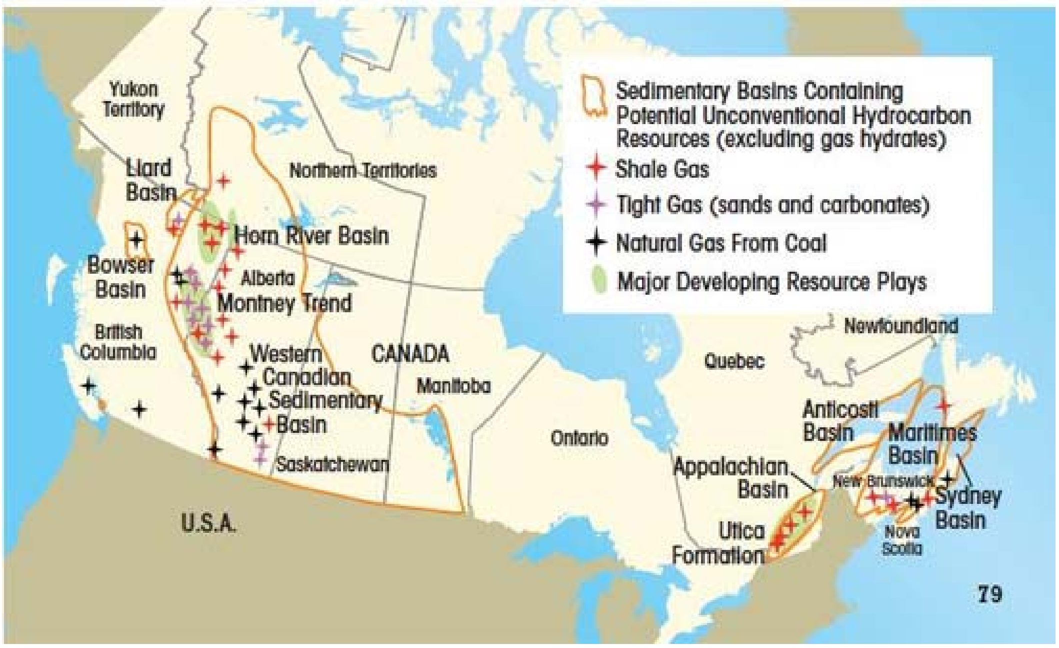
Although Alberta is believed to have extensive unconventional gas reserves they are not included in Figure 2.10 as unconventional reserves have not yet been defined by the AER (Alberta Energy Regulator) to the same extent as proven reserves.

Conventional natural gas reserves typically are found in accumulations or pools. Unconventional reserves are trapped in coal seams, slate formations or tightly packed rock. These resources include coal bed methane, tight gas and shale gas. Alberta's unconventional natural gas resources are in a relatively early stage of development, especially as compared to similar geological formations in the US. However the unconventional natural gas reserves are expected to be substantial.

An assessment of natural gas reserves in place is based on the assessment of the gas in place in the reservoir and the recovery factor. The recovery factor estimates the amount of gas that likely will be recovered from the reservoir as a percentage of the total original gas in place. This factor tends to be lower for unconventional resources as compared to conventional resources and can range from 5 – 40%. We note that assessments of unconventional resources have a high degree of uncertainty because the gas-in-place estimate is difficult to determine for unconventional resources and the recovery factor is highly variable. Note also that the economically recoverable reserve may be much less and is affected by gas prices and the cost of accessing the reserve (which is in turn affected by technology developments).

Unconventional natural gas resources from shale gas, tight gas and coal bed methane (CBM) can be found in Alberta. The Montney Trend formation has resulted in major resources plays in British Columbia and it is expected that similar reservoirs may be found in Alberta. Potential unconventional resources are shown in Figure 2.11.

Figure 2.11
Potential Canadian Unconventional Hydrocarbon Resources



(Oil and Gas Investor, 2012)

Coal Bed Methane

The Alberta Geological Survey (AGS) has estimated that there are 500 trillion cubic feet (TCF) of coal bed methane in place within all the coal in Alberta (initial, ultimate gas in place). However, due to unknown recovery factors the total reserve has not been estimated. There are two developed areas for coal bed methane in Alberta, Horseshoe Canyon and the Mannville formation. Table 2.2 table shows estimates of coal bed methane for these regions from the AER. Reserves from other coal zones in the Province have not yet been established.

Table 2.2
CBM Reserves by Deposit Play Area, 2012

Deposit and Play Subareas	Average Recovery Factor (%)	Initial Established Reserves (TCF)*	Cumulative Production (TCF)	Remaining Established Reserves (TCF)
Horseshoe Canyon	31 %	2.56	1.34	1.22
Mannville	42 %	1.00	0.21	0.78
Undefined		0.02	0.02	--
Total	33 %	3.58	1.57	2.00

(ERCB, 2013)
*TCF = trillion cubic feet

Tight Gas

Tight gas is typically found in sandstone or limestone with very low porosity or permeability. Tight gas reserves have been estimated in a very preliminary way as shown in Table 2.3:

Table 2.3
Estimated Tight Gas Reserves

Region	Estimate (TCF)	Source
Deep Basin / Cretaceous	430	PRCL 2006 report for DOE and industry partners
Deep Basin / Triassic	>1000	Estimate based on BC Montney play, no calculations published
Foothills Cretaceous	>1	Placeholder estimate, no calculations published

(Petrel Robinson, 2010)

Shale Gas

In addition to coal bed methane and tight gas reserves, Alberta has five regions that hold significant shale gas and shale oil reserves. Table 2.4 summarizes the risked shale gas and shale oil resources. In this table, risked gas in place is the estimated gas in place based on geological and technical factors adjusted to take into account the current level of information about the reservoir, the data quality and the current state of technology. The technically recoverable resources are calculated by applying a recovery factor to the risked gas in place. These data are from an EIA report that was based on data published by ERCB in 2012 in their report "Summary of Alberta's Shale and Siltstone Hosted Hydrocarbon Resource Potential".

Table 2.4
Alberta Shale and Siltstone Hydrocarbon Resource Potential

Basin / Formation	Risked Resource In-Place		Risked, Technically Recoverable Resource	
	Oil / Condensate (MM bbl)	Natural Gas (TCF)	Oil / Condensate (MM bbl)	Natural Gas (TCF)
Banff / Exshaw	10,500	5.1	320	0.3
E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
Deep Basin (Nordegg)	19,800	72.0	790	13.3
N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
S. Alberta (Colorado)	--	285.6	--	42.8
Total	139,500	987.1	7,240	200.5

(EIA/ARI, 2012)

Combining the estimates of gas in place for coal beds, tight formations, shale and siltstone suggests that Alberta has on the order of 3,000 TCF of natural gas in place. Assuming an energy density for natural gas of 1,027 Btu per cubic foot, this corresponds to an energy content of about 3,000,000 PJ. Assuming that a fraction of this gas in place eventually becomes established reserves, this high-level analysis suggests that Alberta has unconventional gas reserves of magnitude similar to its reserves of coal and oil shown above in Figure 2.10.

Alberta Electricity – Supply and Demand

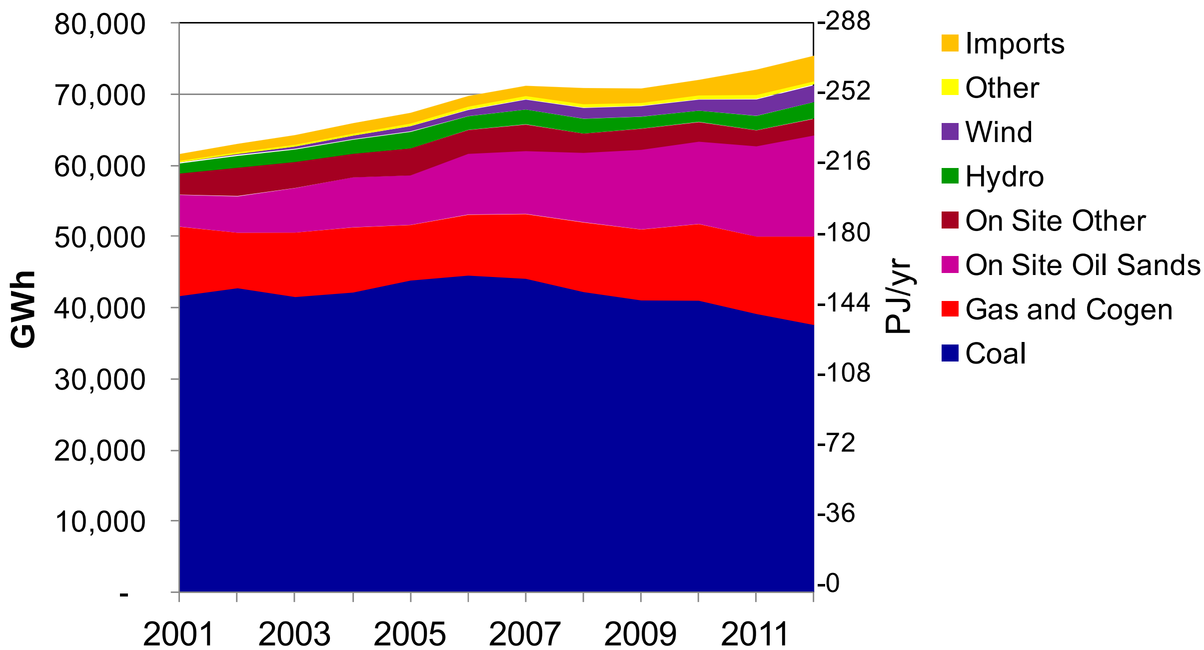
Alberta has a diverse supply of electricity including coal and natural gas fired power plants that provide dedicated power to the electricity grid, electric power supplied to the grid from behind-the-fence generation at industrial sites such as in the oil sands area, renewable generation from hydroelectric power plants, wind generation, and solar. In the future, regulations limiting GHG emissions from electricity generation will begin the phase down of coal-fired power in the Province. (Gazette, SOR/2012-167 August 30, 2012 Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, 2012) Alberta's electrical grid has ties with jurisdictions, but inter-grid power trading is not a major factor in Alberta's electricity supply.

Electricity Supply

When we consider electricity supply, we distinguish between the capacity to generate or produce electric power, and the actual electrical energy that is produced over time. (Energy is power integrated over time and power is the rate of doing work.) Power is expressed in watts, and electrical energy customarily is expressed in watt-hours, although in the Study we often convert watt-hours to joules in order to compare with other energy sources.

As shown in Figure 2.12, electricity generation in Alberta historically has been highly dependent on coal fired power plants. With the expansion of oil sands, an increasing share of electricity generated in Alberta comes from on-site generation in the oil sands. Additionally, the share of electricity generated from wind has been steadily growing.

Figure 2.12
Electricity Generation – History, (AESO), (ERCB, 2013)



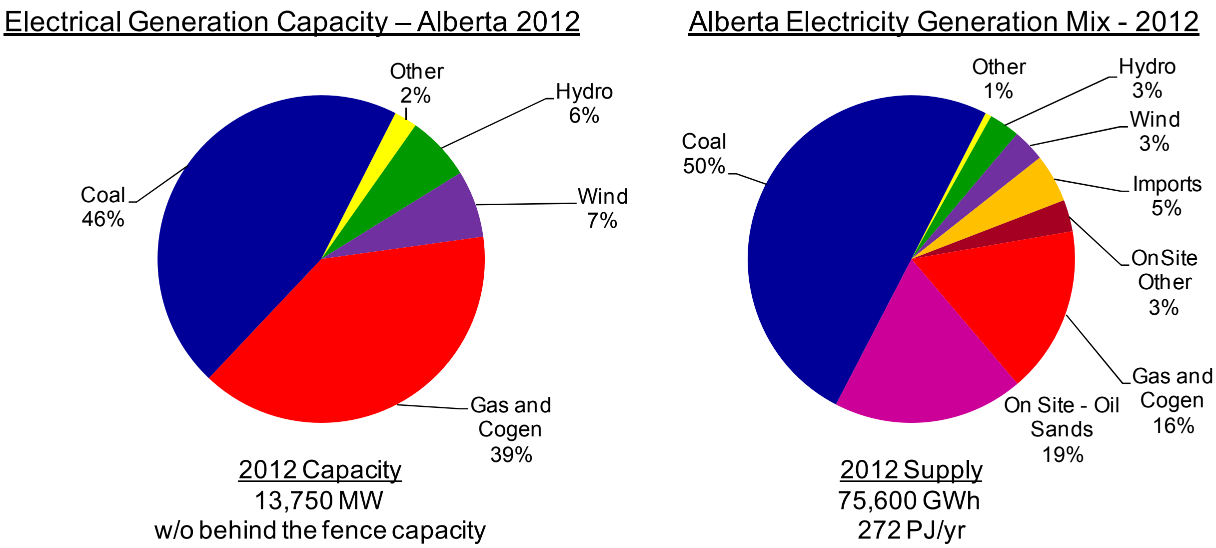
Source: (AESO, 2010, 2011, 2012 Annual_Market_Stats_Data_File.xls), (ERCB, ST-98 2012 Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021, 2012)

Shares of installed grid generating capacity differ from what is actually supplied to the grid because electricity demand varies during the day and over the year and some sources of electricity are easier to bring onto the grid and take off than others, and because some sources of electricity have greater variability than others.

The left-hand chart in Figure 2.13 shows the generating capacity (electric power) that could supply the grid; it does not include behind-the-fence supply from oil sands or other industrial sources. While these behind-the-fence sources can export power to the grid, they do not necessarily produce power for the grid routinely and are not normally thought of as grid supply capacity by the grid operator. The right-hand chart in Figure 2.13 shows the supply of electricity to consumers, which includes behind-the-fence supply from oil sands operations and other industrial sources.

Coal-based electricity generating capacity is 46% of the overall grid capacity in the left-hand chart. Actual supply of electricity from coal is nearly 64% when behind-the-fence generation is excluded from consideration and around 50% when behind-the-fence generation is included.

Figure 2.13
Electricity Grid - Generation Capacity and Supply Alberta 2012, (AESO), (ERCB, 2013), (AESO, Updated_2012_Long-term_Outlook_Data_File, 2012)

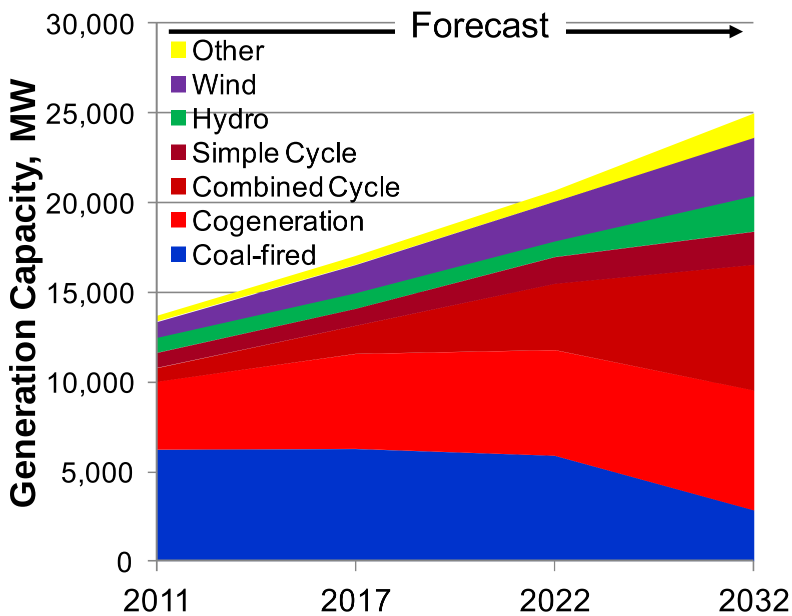


Sources: (AESO, 2010, 2011, 2012 Annual_Market_Stats_Data_File.xls), (AESO, Updated_2012_Long-term_Outlook_Data_File, 2012), (ERCB, ST-98 2012 Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012–2021, 2012)
Gas and Cogen generation capacity of 39% includes on-site oil sands

Canadian federal regulations finalized in 2012 restrict the greenhouse gas emissions from coal fired power plants to 420 tonnes CO_2e/GWh, which is approximately the level of GHG emissions from a combined-cycle natural gas power plant. (Gazette, SOR/2012-167 August 30, 2012 Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, 2012) As a result of the cap, no new coal-fired power plants will be built unless they include carbon capture and sequestration (CCS). Existing coal-fired power plants will be shut down as they reach certain operating lifetime milestones unless CCS is integrated into plant operations.

Electricity generation forecasts in Figure 2.14 show the potential impact of these regulations. The share of coal-fired electrical generation capacity would be reduced from 46% in 2011 to eleven percent by 2032. This forecast also predicts small increases in wind and hydroelectric power (12% to 21% by 2032) and a large increase in natural gas generating share from 39% in 2011 to 62% in 2032.

Figure 2.14
Electricity Capacity Forecast

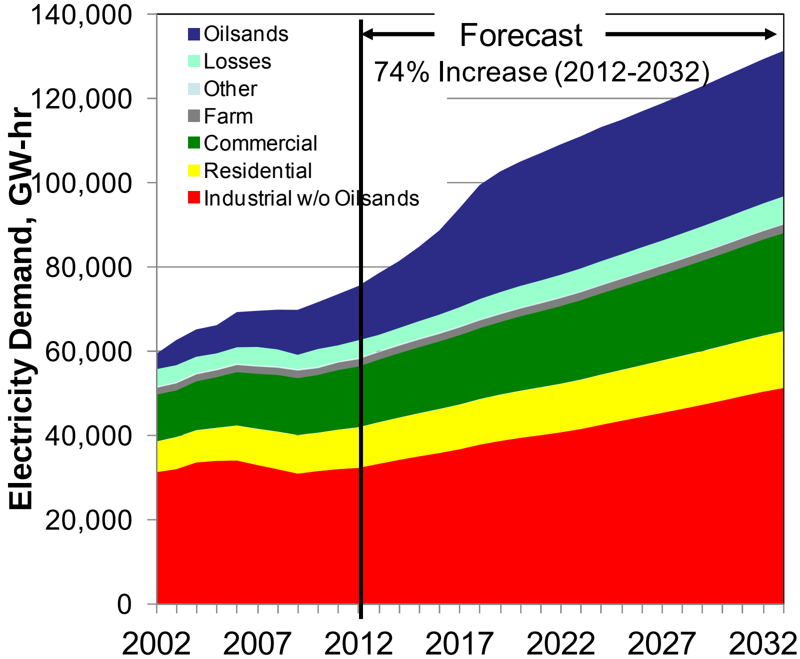


Source: (AESO, Updated_2012_Long-term_Outlook_Data_File, 2012)

Electricity Demand

Electricity demand, as shown in Figure 2.15, is driven primarily by demand by oil sands and industrial sectors. The share of oil sands demand increases significantly over the period evaluated (to 2032) as a result of the high projected growth of oil sands demand. (AESO, Updated_2012_Long-term_Outlook_Data_File, 2012)

Figure 2.15
Historical and Forecast Electricity Demand, Alberta



(AESO, Updated_2012_Long-term_Outlook_Data_File, 2012)

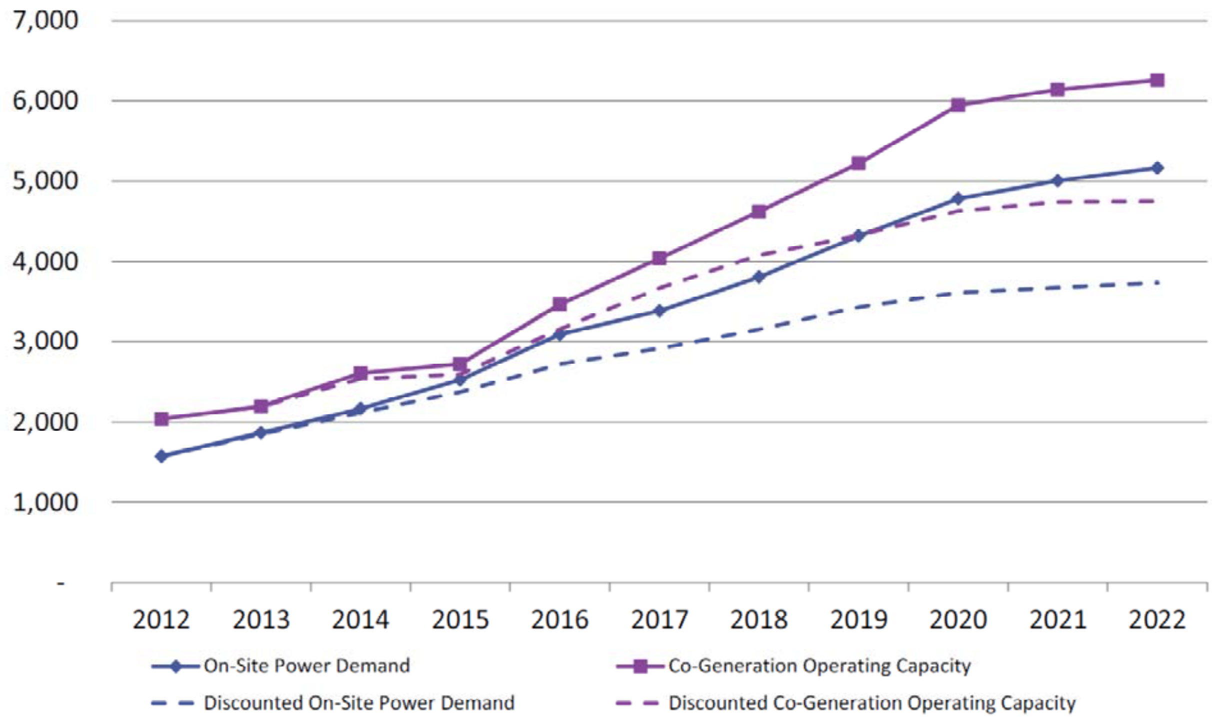
As the oil sands demand for electric power grows, it is predicted that on-site generation will also grow (see Table 2.5).

Table 2.5
Forecast Growth of Electricity Demand in Alberta

2011-2032	Growth, %/yr
Oil Sands	5.7
Non-Oil Sands	2.2
Commercial	2.3
Residential	1.7
Overall	2.7

Figure 2.16 shows the growth expected in electricity demand and supply by the Oil Sands Development Group under several scenarios. The discounted scenarios take into account that some of the projects will not actually be built. (Oil Sands Development Group, 2013)

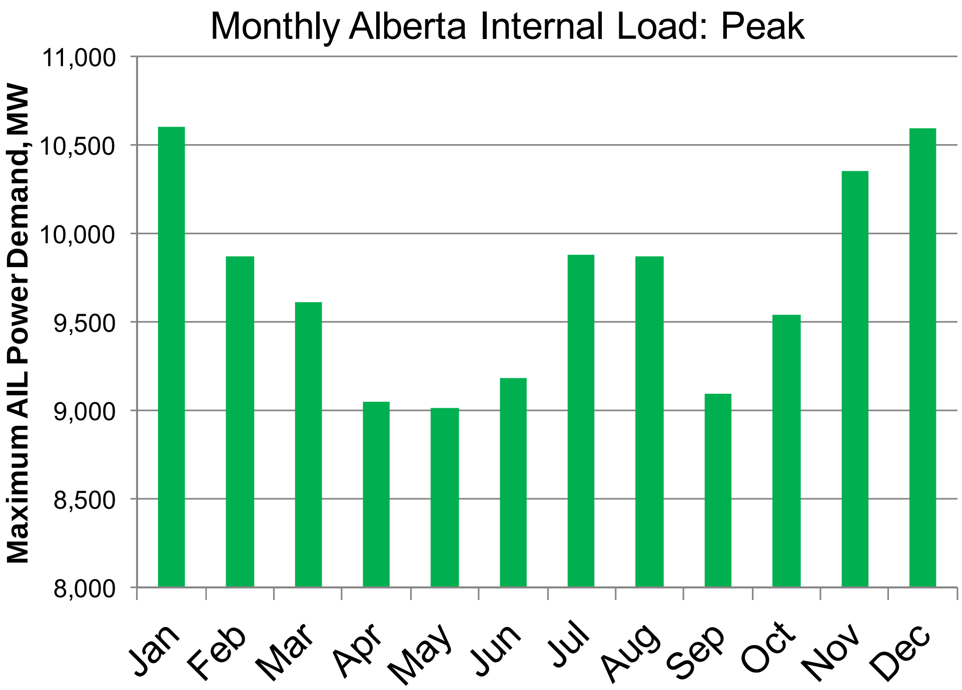
Figure 2.16
Oil Sands Developers Group - Anticipated On-Site Demand and Generation Forecast – Medium Range 2013



(Oil Sands Development Group, 2013)
Note: Forecast basis is for medium range projects – project would be built to the most probable or planned scope in a business as usual environment

Annual demand for electricity in Alberta exhibits two peaks. (AESO, Updated_2012_Long-term_Outlook_Data_File, 2012) As shown in Figure 2.17, one peak corresponds to winter months when there is greater demand for lighting and heat. A second, somewhat smaller peak for electricity demand occurs in the summer as a result of air conditioning demand.

Figure 2.17
Monthly Alberta Internal Load - Peak



Source: (AESO, Updated_2012_Long-term_Outlook_Data_File, 2012)

Alberta Energy for Heat

Alberta heat use is driven by demand for industrial heating for factories, petrochemical and chemical facilities, and pulp and paper facilities, heat for bitumen production and space heating for residential, commercial and industrial sectors.

We estimated heat demand in Alberta in the following manner. We subtracted the natural gas for electricity production from the total natural gas consumed in Alberta. We then added the energy from propane use and the wood for domestic consumption to arrive at an annual consumption of energy for heat of around 1480 PJ/yr. Assuming 85% efficiency, this amount of energy will supply 1270 PJ/yr of heat to Alberta. We were unable to sufficiently document biomass used to supply heat for industrial processes. In addition, we did not break out the portion of natural gas for cogeneration that is used for electricity production. Our assumption was that the primary role of natural gas for cogeneneration was to supply heat; electricity generation was secondary. Thus, to avoid double counting natural gas we only counted that used in cogeneration as a source of heat and not as a source of electricity.

Table 2.6
Estimated Generation of Heat from Alberta Energy Sources

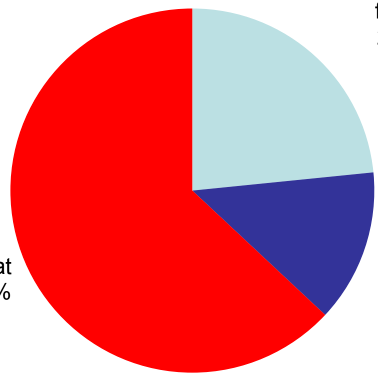
	Energy	Delivered Heat*
	PJ/yr	PJ/yr
Total Alberta natural gas consumption in 2012	1,750	
Natural gas used to generate electricity	294	
Energy for Heating		
Net gas for heat	1,456	1,240
Residential Natural Gas	155	130
Natural gas for industrial and commercial	1,301	1,110
Propane and propane mixes - Alberta Sales	16	10
Household wood and wood pellets	7	4
Total energy for heat	1,479	1,254

* Assumes 85% efficiency of generation of heat from energy source
Source: (ERCB, ST-98, 2013)

Summary – Energy Commodity Consumption in Alberta

Alberta is estimated to need around 2,000 PJ/year of commodity energy. As shown in Figure 2.18, approximately 63% of this energy must be supplied as heat, 23% as transport fuel, and 14% as electricity. Energy to supply heat includes what is used in the oil sands to generate steam and the electricity, which is a byproduct of cogeneration.

Figure 2.18
Delivered Energy Alberta 2012 – 2000 PJ/yr



Total Alberta Energy Demand: ~2,000 PJ/yr in 2012

(AESO, Updated_2012_Long-term_Outlook_Data_File, 2012), (Cansim, Table 134-0004 Supply and Disposition of refined petroleum products, monthly (cubic meters), ?), (ERCB, ST-98, 2013)

Section 3.

Energy Attributes

Energy Attributes

While many types of energy are fungible, there are key features of supplied energy that must be considered when determining energy substitution or a new mix of sources.

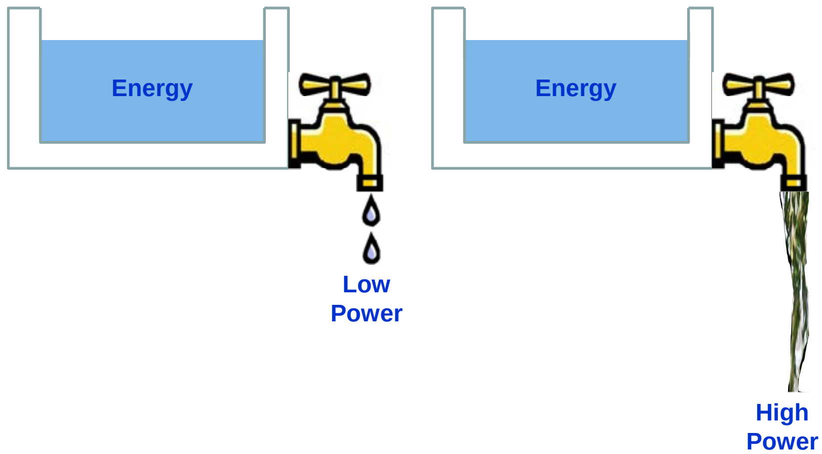
Delivering Energy to the Customer

Understanding the needs of the energy commodity consumer is a key factor in determining the potential for energy commodity production. In general, consumers prefer energy commodity supplies that are readily available, that are competitively priced, that can deliver the required energy at the required rate and that have low environmental impact. More specifically, electricity consumers require reliable supply that is available on-demand at a stable voltage. Consumers of transportation fuels require fuels that can be safely stored on-board the vehicle at sufficient energy density to meet their transportation needs. Heat must be supplied at the correct temperature and at the rate required.

The needs of the industrial consumer differ from those needs of the residential or commercial consumer. The industrial consumer often will require heat at much higher temperatures than a residential or commercial consumer. For example, the heat needs of an in situ bitumen producer are quite different from the heat requirements of a family home in terms of both quantity and temperature. The industrial customer also may require electrical power at much higher voltages than a residential or commercial customer. An example would be the difference between residential electrical demand as compared to that of a large data processing center or an electrical arc furnace operator. Industrial consumers may have the ability to manage loads so that they can purchase electricity during low demand / low cost periods. For example, data centers can shift certain heavy loads to the nighttime when costs are lower.

We also must differentiate between the supply of energy and the supply of power. This is a critical differentiation, commonly overlooked in the discussion of energy supply. Energy is the capacity to do work, whereas power is the delivery of energy over time. As shown in Figure 3.1, two resources may contain the same amount of energy but differ in their ability to supply power. In considering energy supply we must consider delivery of energy at the rate needed by the consumer.

Figure 3.1
Supply of Energy vs. Supply of Power



Stock versus Flow

Another way to differentiate energy resources is to consider the differences between those based on a stock of resource reserves versus those based on a flow of the resource.

Stock-based energy resources are supplied from a reservoir of stored capacity that is much greater than the annual production of the resource. Increased rates of energy production are realized by capital investment or technology improvements that enable more energy to be drawn from the reservoir at a faster pace. These reservoirs have a finite limit of resources and are not replenished. Measurements of reserves can be made based on criteria such as extent of exploration and the cost of recovery. However as new recovery techniques are developed and the economics of resource recovery change, the quantity of material in existing reserves can change. Examples of stock based resources include coal, oil, natural gas, and uranium.

Flow-based resources are not produced from reservoirs and thus there is no inherent storage capability or reserves for these types of resources. The rate of production of the energy resource depends on the rate that the resource is available. Flow-based resources are replenished more or less continuously but the rate of replenishment may change over time. There may or may not be some short-term storage potential, but not nearly enough to overcome long periods of scarcity. Examples of flow-based energy resources are those based on wind, solar, and biomass.

Some resources are hybrids of stock and flow. There may be a reservoir of the resource that is replenished but the rate of replenishment is slow. An example of a hybrid resource is timber; it may take many years to replenish existing forest stock. Hydroelectric power is also a type of hybrid resource, but for different reasons. Run of river hydroelectric power is generally a flow resource. Dam-based hydroelectric power is more like a stock resource with slow annual replenishment. Geothermal energy is another type of hybrid energy resource because the rate of energy production often depends on the rate that heat is resupplied. If we draw too much energy too quickly, the geothermal resource may become depleted until the energy is resupplied from the earth.

Energy Commodity Production

The conversion of primary energy resources (e.g. oil, coal, biomass, solar insolation) to energy commodities (e.g. electricity, transportation fuel, heat) for use by energy consumers follows different pathways for each primary energy source and energy commodity

Electric Power Production

In our analysis we assume the following efficiencies for electric power production from different energy resources.

Efficiency of power production:

- Coal (NETL, Cost and Performance Baseline for Fossil Energy Plants, 2007)
  - Modern supercritical 39%
  - Modern supercritical: with carbon capture and storage (CCS), 27%
- Natural gas (NPC, 2007)
  - Combined cycle: 51%
  - Single cycle: 32%
- Oil: 39% (assumes the same efficiency as coal fired power)
- Biomass: 26% (NREL, Renewable Electricity Futures Study Renewable Electricity Generation and Storage Technologies, Volume 2 of 4, 2012)
- Nuclear: 39% (assumes the same efficiency as coal fired power)

Electricity Generation Characteristics

The Alberta electrical grid currently is supplied by a range of resources which follow different pathways to deliver electricity and which have different grid supply characteristics. The challenge to the electricity grid operator is how to balance these different characteristics and still supply electrical power that meets the needs of the consumer. Three key characteristics to describe the electricity sources are dispatchability, variability and intermittency.

- Dispatchability is the ability of the power generator to ramp up or down power production when the grid requires a change in power delivery.
- Variability is the change in the supply of power to the grid based on changes that are not within the control of the power plant operator. For example, gusty winds will change the output of a wind turbine, or clouds will change the output of a solar cell.
- Intermittency is the extent to which a power source is unintentionally stopped or unavailable. Intermittency may be predictable such as the diurnal nature of solar power.

Table 3.1 shows a high-level analysis of the characteristics of electrical power supply for different resources and pathways.

Table 3.1
Electricity Generation Characteristics by Energy Source

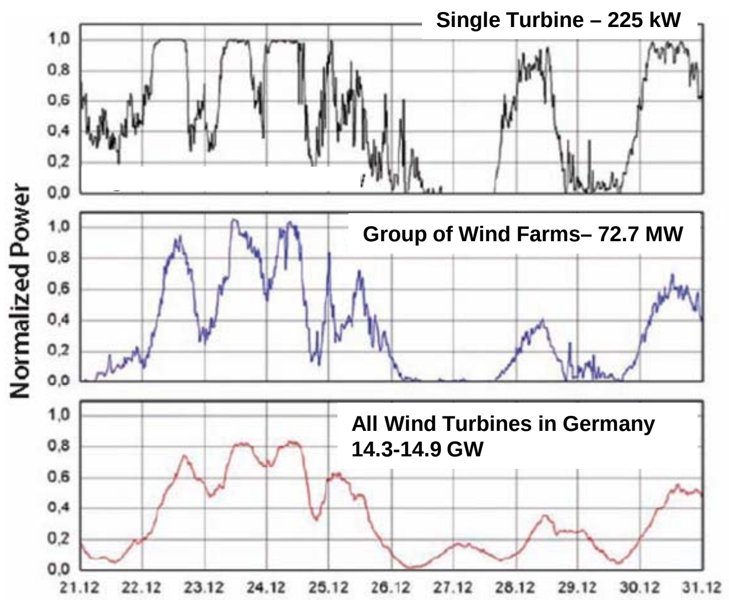
Power Source	Dispatchable	Variable	Intermittent
Coal	Moderate	Low	No
Natural Gas	High	Low	No
Oil	Moderate	Low	No
Nuclear	Low	Low	No
Hydroelectric power – reservoir	High	Low	No
Hydroelectric power – run of river	Low	Moderate – highly seasonal	Not available in winter months in Alberta
Wind – utility-scale	Low	High – minute to minute and diurnal/seasonal	Not available at low or high wind speeds
Solar – distributed, grid connected	Low	High – minute to minute and diurnal/seasonal	Diurnal
Biomass	High	Low	No
Geothermal (heat pump)	Moderate-High	Low	No

Grid operators are facing increasing challenges in supplying electricity. Demand for electric power is increasing as is the demand for power quality. Concerns about greenhouse gas emissions are leading to a decreasing supply of low variability / intermittency and moderately dispatchable power supplies as a result of the reduction in coal-fired power plant capacity. Increased use of low dispatchable and highly variable resources such as wind requires increased planning, new technologies and system support services for the grid operator. New technologies and management strategies being developed and implemented for the grid operator to manage these new challenges include:

- Increased integration with other grids (e.g. United States, British Columbia, and Saskatchewan)
- Demand side management, e.g. load shedding at peak times when demand outstrips capacity
- Implementation of wind or solar electricity production over a wider geographic area to decrease variability
- Improved wind / solar forecasting tools
- Energy storage

Figure 3.2 demonstrates the potential variability in electricity generation from wind turbines. The top figure shows the variability from a single turbine over ten days when there was a wide ranging weather pattern affecting Germany and much of Europe. The middle figure shows the variability of a group of wind farms in the same general geographic location as the wind turbine in the top graph over the same ten-day period. The bottom figure shows the variability in all wind farms over the same time period but in all of Germany. Variability in electricity generation is shown to decrease with more wind turbines operated over a greater area. While variability is dampened by increasing the number of turbines and widening the geographic area, clearly large weather disturbances can affect wind generation over a wide area, an important consideration when supplying the grid with wind based power.

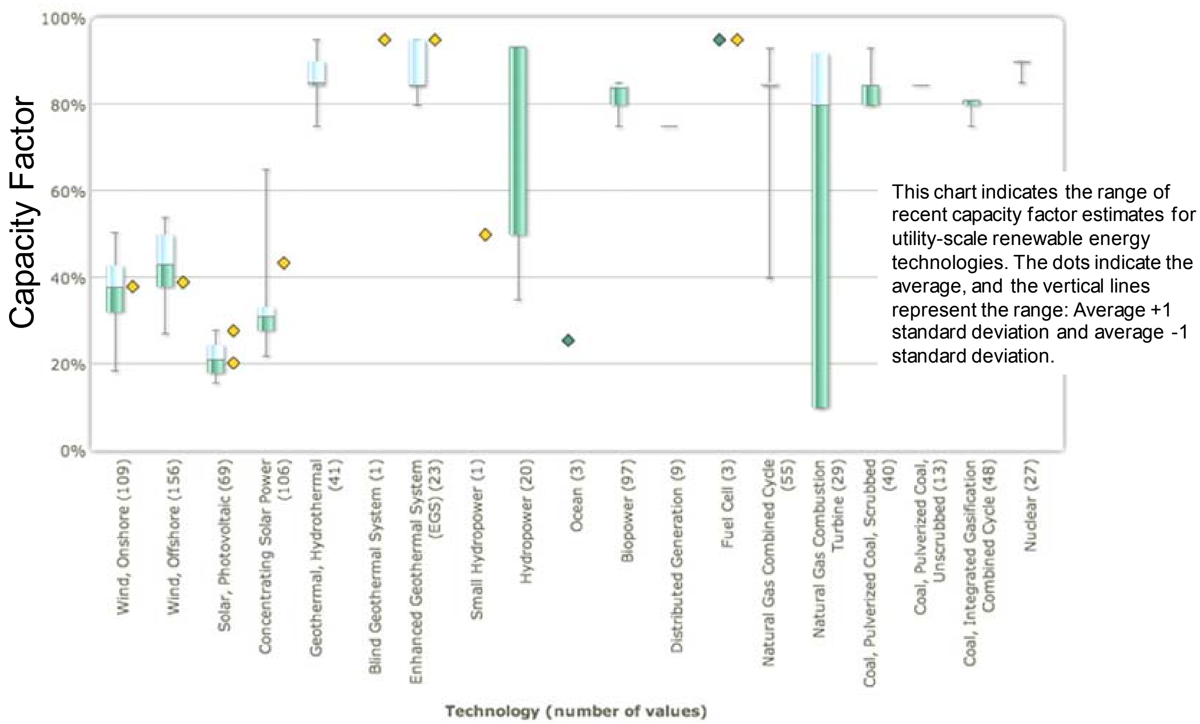
Figure 3.2
Variability Wind Turbines Germany



(Hannele, 2008)

Figure 3.3 is taken from a study by the US National Renewable Energy Laboratory. (NREL) The figure provides a comparison of utilization rates / capacity factors for various means of electric power generation. Ultimately, the major challenge of electric power grid management is achieving the right mix of power sources needed to ensure that enough electric power can be dispatched to meet fluctuating demand while maintaining reliability and stability of the grid.

Figure 3.3
Capacity Factors for Electricity Generation (from NREL Utility Energy)



Heat Production Characteristics

Heat is generated in Alberta from a number of sources including natural gas, coal, solar energy, cogeneration with electricity, biomass and geothermal energy. Heat often is produced near the point of use as compared to electricity which is more typically generated at large, utility-scale plants and then distributed to consumers through the electrical grid. Two important characteristics for delivering heat are the rate and temperature at which heat energy is supplied. For example, although there are extensive supplies of geothermal-based heat available in Alberta, the supply temperatures are too low to be used directly in most industrial applications. We discuss the pathways for delivering heat at greater length when discussing each energy individual resource.

Transportation Fuel Production Characteristics

Alberta's supply of transportation fuels is derived primarily from crude oil and bitumen. Developing sources of transportation fuel in Alberta include ethanol biofuel from wheat fermentation, biodiesel from oil seeds, compressed natural gas (CNG), liquefied natural gas (LNG) and electricity. Key characteristics of developing transportation fuels include:

- The ability to use the fuel in the existing transportation fuel supply network
- Whether the existing vehicle fleet can use the fuel or new types of vehicles will be required
- The energy density of the fuel
- The time needed to refuel the vehicle
- The environmental impact of the fuel.

To compare the different types of transportation fuel in the Study, we used three different types of personal use vehicles: one that uses a spark ignition engine, a second that uses a compression ignition engine and a third that uses batteries and electric motors, without auxiliary power from an onboard engine. The three types of vehicles and their fuel efficiency as rated by the US EPA are shown in Table 3.2. (EPA U. , 2012). We converted the EPA data to units more commonly used in Canada in Table 3.2a.

Table 3.2
Vehicle Characteristics from US EPA

			EPA MPG		
Model	**Energy Commodity**	**Units**	**City**	**Combined City/ Highway**	**Highway**
2012 VW Golf 5 cyl, 2.5 L, Manual 5-spd	Gasoline	MPG	23	26	33
2012 VW Golf 4 cyl, 2.0 L, Manual 6-spd	Diesel	MPG	30	34	42
2012 Nissan Leaf Automatic	Electricity	kWh/ 100 mile	32	34	37
		MPGe	106	99	92

MPGe is the miles per gallon equivalent to the inverse of kWh per 100 miles, a simple conversion of units.

Table 3.2a
US EPA Vehicle Characteristics Converted to Customary Canadian Units

			Based on EPA MPG		
Model	**Energy Commodity**	**Units**	**City**	**Combined City/ Highway**	**Highway**
2012 VW Golf 5 cyl, 2.5 L, Manual 5-spd	Gasoline	l/100 km	10.2	9.0	7.1
2012 VW Golf 4 cyl, 2.0 L, Manual 6-spd	Diesel	l/100 km	7.8	6.9	5.6
2012 Nissan Leaf Automatic	Electricity	kWh/ 100km	19.9	21.1	23.0
		l/100 km	2.2	2.4	2.6

Energy Pathways

In the Study, resources are converted to finished energy commodities (heat, electricity, and transportation fuels) via a number of pathways. Each pathway uses a specific technology mix to generate the commodity. As each resource is discussed in Section 4, the pathways are clearly defined in terms of technology used, inputs and outputs and the scale of the technology. The metrics are resource- and pathway-specific. Not all resources will produce all three commodities.

Figure 3.4 shows the general relationship between energy resources, pathways and the energy commodities.

Figure 3.4
Energy Resources, Pathways and Commodities

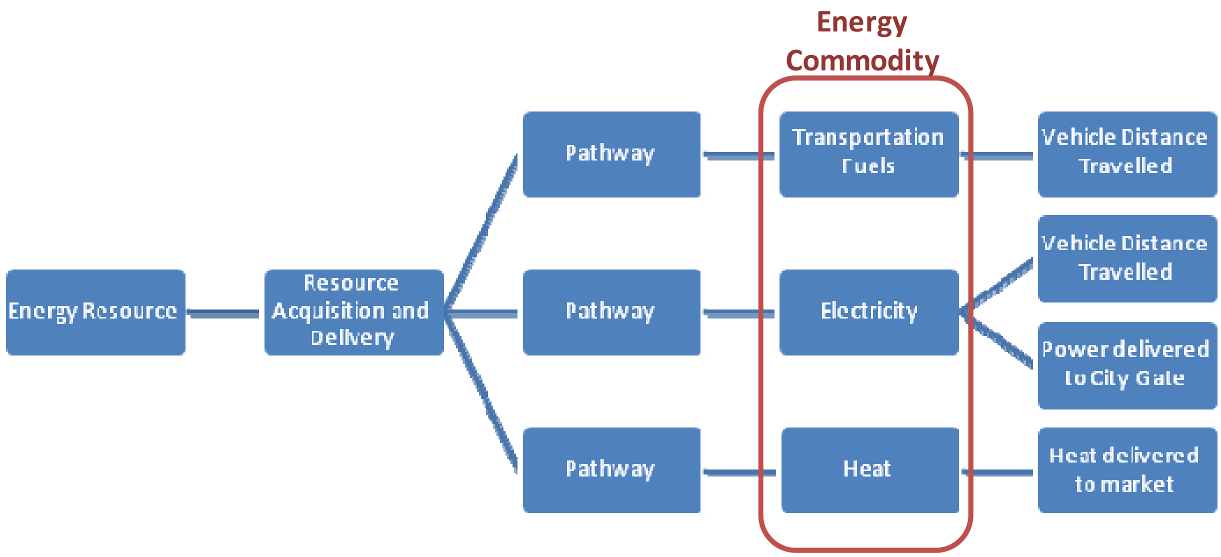


Table 3.3 shows the pathways and commodities considered in the Study.

Table 3.3
Energy Resources and Commodities

Energy Resources	Electricity	Heat	Transport Fuels
Hydrocarbon based			
Coal	√	√	NA
Oil (including bitumen)	√	√	√
Natural Gas	√	√	√
Biologically based			
Crops – food crops and non-food crops	√	√	√
Forestry products	√	√	√
Waste material from crops and forestry	√	√	√
Manure	√	√	√
Non-hydrocarbon, Non-Bio based			
Hydroelectric power	√	NA	NA
Wind	√	NA	NA
Solar energy for electricity	√	NA	NA
Solar energy for heating	√	√	NA
Geothermal energy	√	√	NA
Landfill gas	√	√	√
Municipal Solid Waste	√	√	√
Nuclear	√	√	NA
Electricity to Transport and Heat			
Transport	NA	NA	√
Heating	NA	√	NA

NA: Not applicable

Section 4.

Energy Metrics

Energy Metrics

No single parameter defines an ideal energy resource because each energy resource requires an assessment of the total amount that is available, the potential to produce useable energy from the resource, and the impact of converting the primary resource into a commodity energy product.

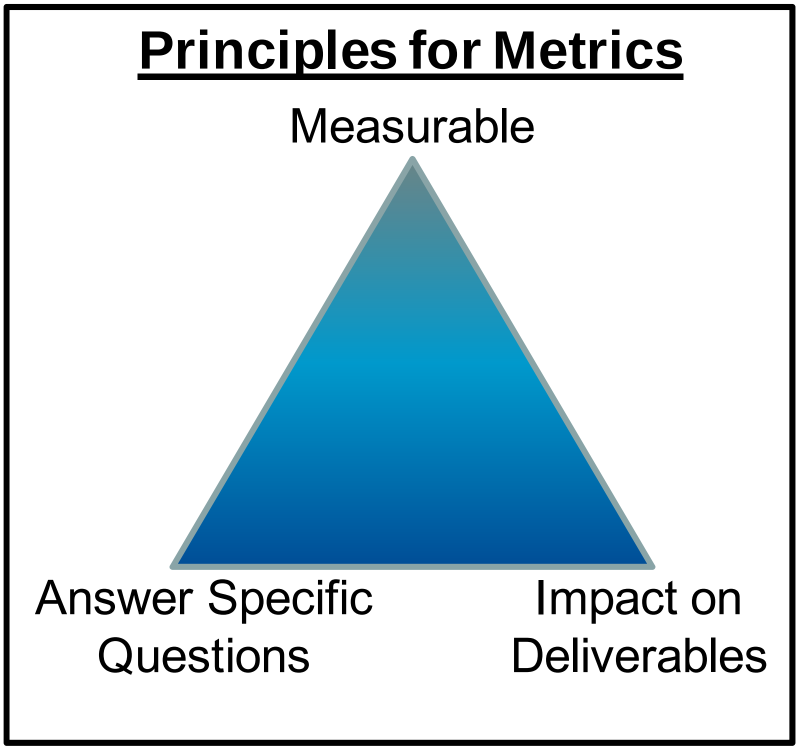
The process of energy resource assessment involves various metrics which differ across resources. A reference set of metrics can aid in comparing the different energy resources and makes it easier to draw conclusions as to their utilization potential. Hence, it is important to define metrics that can effectively quantify the diverse resources and the impact of their conversion to energy commodities for end users.

The challenge lies in appropriately defining the metric and establishing the boundaries of analysis for each metric. For example, the energy available from canola produced in Alberta depends on the analysis boundaries. In one case, we could set the boundary to include the current canola crop that is produced in Alberta. Alternatively, we could set the boundary to include all canola that could be harvested in Alberta if all farmland was converted to canola production. Similarly, we can assess the wind energy resource in Alberta as the current wind energy capacity or as the potential capacity if wind turbines were installed in all the available areas with high wind.

With guidance from Alberta Energy and our Technical Steering Committee, we gave consideration to a few key principles for metrics as depicted in Figure 4.1.

- Is the metric applicable and measureable across various primary energy sources and commodity energy products?
- Does the metric answer specific questions about energy sources and products?
- Does the metric address Study deliverables appropriately?

Figure 4.1
Design Principles for Metrics



Establishing Study Boundaries, Fundamental Principles and Assumptions

Our intent is to provide energy metrics on a transparent, first principles engineering basis, using the following Study boundaries:

- The Study only addresses energy technologies in the context of Alberta.
- The Study does not address projected market share of an energy commodity.
- The Study does not address end use energy cost (i.e. cost of bringing the energy commodity to the consumers).
- The Study does not address the effects of policy on energy development.

Metrics Definitions

We have defined four categories of metrics: Production and Capacity, Energy Density, Efficiency and Energy Consumption, and Environmental.

Production and Capacity Metrics

1. **Remaining Established Reserve Potential, Primary Source**

   This metric is only applicable for primary sources that are defined as stock type resources. It is a measure of established reserves as reported by AER.

2. **Actual Annual Production, Primary Source**

   The annual production of the primary energy resource (e.g. coal, oil, etc). This metric is only applicable for primary energy resources that are defined as stock type sources. The production data are from 2012 unless otherwise noted and are taken from Alberta government sources as noted in the metrics table.

3. **Available Commodity Production Capacity (Current Installed Capacity)**

   The actual production capacity for the commodity that is specific to the energy resource and pathway. The capacity numbers are as reported in Alberta government sources or from company websites, as noted in the metrics table.

4. **Current Actual Commodity Produced**

   This metric reports the commodity produced for a given energy resource and pathway in Alberta; where possible the data are for 2012. The data come from Alberta government sources as noted in the metrics table. In some cases the data are not reported (such as the actual production of bioethanol in Alberta). In this case, the metric is shown as not available.

5. **Current Actual Commodity Produced - Percent of Alberta Consumption**

   This metric is calculated as the value in Metric 4 (current actual commodity produced) as a percentage of the total Alberta consumption. For electricity, the sum of electricity from available Alberta commodities is less than 100% of Alberta demand because Albert imports electricity. Conversely, the sum of all available commodities for transportation fuels is greater than 100% of Alberta demand because Alberta exports transportation fuels.

6. **Commodity Production if all Alberta Primary Source is Converted to Commodity**

   This metric considers the amount of the commodity (transportation fuel, electricity, heat) that could be produced if all of the primary resource were converted into the commodity, regardless of the current production of the commodity. The metric is intended to give an upper bound for the maximum production level of each commodity from a particular primary resource. For stock resources (coal, oil, bitumen, natural gas), the maximum primary source available is based on current average annual production. For flow resources (e.g. biomass, wind, etc.) we estimated a maximum available primary resource, which might not be achievable once all constraints are taken into account. For example, it is unlikely that Alberta would devote all of its cropland to biofuels at the expense of food production. Likewise it is unlikely that Alberta would cover all or a major portion of its cropland for utility solar PV at the expense of food and biomass. There is no intent to suggest that such production levels are achievable with current technology. Note that each commodity must be considered separately, since the calculation consumes all of the available primary resource for the chosen commodity.

The basis for the calculations is in Table 4.1.

Table 4.1
Basis for Calculating Commodity Production if All Primary Resource is Consumed

Resource	Commodity	Calculation Basis
Coal	Electricity	All coal annually produced in Alberta is combusted to produce steam which is used to generate electricity with a power plant conversion efficiency of 39%
Coal	Heat	All coal annually produced in Alberta is combusted to produce steam with a boiler efficiency of 85%
Oil (Crude Oil, Bitumen Mined and Bitumen In situ)	Transportation Fuels	All oil annually produced in Alberta is processed in a refinery to create transportation fuels.
Oil (Crude Oil, Bitumen Mined and Bitumen In situ)	Electricity	All oil annually produced in Alberta is combusted in a power plant with 39% conversion efficiency to produce electricity.
Oil (Crude Oil, Bitumen Mined and Bitumen In situ)	Heat	All oil annually produced in Alberta is combusted to produce steam with a boiler efficiency of 85%.
Natural gas	Transportation Fuels	All natural gas produced annually in Alberta is processed and compressed to make CNG for use as a transportation fuel.
Natural gas	Electricity	All natural gas produced annually in Alberta is processed and then used to make electricity with a power plant conversion efficiency of 51%
Natural gas	Heat	All natural gas annually produced in Alberta is combusted to produce steam with a boiler efficiency of 85%.
Hydroelectric power	Electricity	Based on a report by Hatch engineering that shows developable hydroelectric power sites in Alberta

Resource	Commodity	Calculation Basis
Wind	Electricity	All farm and cropland is used for wind farms with a capacity factor of 31%
Solar PV Distributed	Electricity	All available residential, commercial/industrial and farm rooftops have solar photovoltaic modules with a conversion efficiency of 10% and an average solar insolation of 1200 KWh/KW.
Solar PV Utility	Electricity	All farm and cropland is covered in solar arrays with a spacing of 8 acres/MW and an average solar insolation of 1200 KWh/KW.
Solar Thermal	Heat	All available residential, commercial/industrial and farm rooftops have solar thermal collectors with an average size of 3 – 5 MW
Geothermal	Electricity	Electricity that could be produced from available geothermal sources in Alberta
Geothermal	Heat	Production of heat from distributed ground source based geothermal.
Biomass – Ethanol	Transportation Fuels	All of the wheat, tame hay, corn and crops grown in annually in Alberta are converted to ethanol using conventional fermentation processes.
Biomass – Biodiesel	Transportation Fuels	All canola grown annually in Alberta is converted fatty acid methyl ester (FAME) using a conventional process.
Biomass Combustion	Electricity	All biomass in Alberta: sustainable forest production, forest waste, agricultural waste and food crops are combusted with an overall efficiency to electricity of 26%
Biomass Combustion	Heat	All biomass in Alberta: sustainable forest production, forest waste, agricultural waste and food crops are combusted with an overall boiler efficiency of 60%.
Anaerobic Digestion	Electricity	All Alberta manure generated is digested anaerobically and the biogas converted to electricity at a conversion efficiency of 20 – 30%.
Anaerobic Digestion	Heat	All Alberta manure generated is digested anaerobically and the biogas converted to heat at a conversion efficiency of 85%.
Landfill Gas	Electricity	All Alberta MSW is collected in a single landfill that is modeled to be 20 years old. Landfill gas is collected and combusted with an overall efficiency to electricity of 30%
Landfill Gas	Heat	All Alberta MSW collected annually is collected in a single landfill that is modeled to be 20 years old. Landfill gas is collected and combusted with an overall efficiency to heat of 85%.
MSW	Electricity	All Alberta MSW collected annually is incinerated with an overall efficiency to electricity of 20 %.
MSW	Heat	All Alberta MSW collected annually is incinerated with an overall efficiency to heat of 50%.

7. **Commodity Production if all Alberta Primary Source is Converted to Commodity, Percent of Alberta Consumption**

This metric is calculated as the value of Metric 6 expressed as a percentage of Alberta total consumption. This metric gives an idea of the extent to which an energy resource can fulfill Alberta's energy needs. In a number of cases, maximum production of a commodity greatly exceeds current Alberta consumption.

Energy Density Metrics

8. **Primary Source Energy Density (LHV)**

This metric is a measure of energy density of the resource on a lower heating value basis. The data are sourced from (Argonne, 2008). Lower heating value is a measure of the energy content of a material and is determined by measuring the higher heating value of the material and then subtracting the heat of vaporization of the water vapor from the higher heating value. The measure assumes that the latent heat of vaporization of water from fuel combustion is not recovered.

9. **Primary Source Energy Density (HHV)**

This metric is also a measure of the energy density of the resource, except that it is measured on a higher heating value basis (i.e. the heat of vaporization of water from fuel combustion is included in the heat measurement). This measurement assumes that the latent heat of vaporization of water can be recovered and used. The data are sourced from Argonne National Laboratory (Argonne, 2008).

10. **Transportation Fuel, Weighted Average Energy Density**

This metric measures the energy density of the commodity, transportation fuels. For transportation fuels produced from oil, this metric represents the weighted average of the gasoline and diesel produced based on the rates of production from Alberta refineries. In the case of bioethanol and biodiesel, this metric reports the energy density of the respective fuels.

Efficiency and Energy Consumption

11. **Energy Consumption**

This metric is a measurement of the energy consumed in making the energy commodity from the resource for a given pathway. The energy consumed is measured as the sum of the external energy inputs plus the energy losses due to inefficiencies. The energy consumed does not include the energy to make the conversion facility (e.g. the energy to build a nuclear power plant is not included as energy consumption). The metric is reported as energy consumed to make the commodity / energy in the commodity.

12. Net Energy Ratio

Net energy ratio is defined in many ways in the literature. For the Study, we have chosen to define net energy ratio as the energy in the commodity divided by energy to convert the primary resource to the commodity plus the energy in the primary source:

Net Energy Ratio = (Energy in the Commodity) / (Energy to convert the primary source to the commodity plus the energy in the primary source)

As in the energy consumption metric, the energy to build the conversion facilities is not included in the measurement of the energy to convert the primary source to the commodity. The conversion energy includes the external energy inputs and the energy losses due to inefficiencies in the conversion process.

13. Electricity Conversion Efficiency

This metric represents the overall efficiency of converting the resource to electricity. This efficiency includes:

- Gathering inefficiencies— e.g. landfill gas collection systems are only approximately 85% efficient
- Conversion efficiencies and losses to heat – boilers, turbines and generator efficiencies
- CCS – efficiency losses due to the additional energy requirements for capturing CO_2 and sequestering it
- Line losses – for electricity that is delivered to city gate, 3.4% line losses are included in the calculation (average for Alberta grid (AESO)). For electricity that is delivered via the grid, e.g., efficiencies for distributed solar photovoltaic, pathways do not include line losses.

14. Distance Delivered

Distance delivered measures the distance delivered from electricity and liquid transportation fuels produced from the energy resource. The vehicles used to evaluate distance that can be produced from each fuel are shown in Table 3.2 in Section 3.

Environmental Metrics

15. Greenhouse Gas Emissions

Greenhouse gas emissions are based on a life cycle analysis (LCA) basis which begins with the production of the resource, the conversion of the resource to desired commodity, the transport of the commodity to the end user, and the use of the energy commodity by the end user. In many cases LCA GHG emissions are reported from comprehensive meta-studies. We have simplified the analysis with appropriate assumptions using average energy consumption and GHG emissions from the intermediate steps in converting the source of energy to end use. The GHG emissions do not include GHG from the construction of the conversion facility. Emissions are reported on a CO_2 equivalent basis and are calculated from CO_2, N_2O and methane emissions using Global Warming Potential (GWP) factors from the IPCC Fourth Assessment Report. (Solomon, et al., 2007)

16. Land Use

Land use is estimated as the land used in the process of extracting the resource and by the land occupied by the conversion facility. Land use for the construction of power lines was not included as it is highly site specific. In the case of wind farms, land use was assumed to include only the land used for the pads that the turbines stand on, since the land adjacent to the pads is often used for crops or grazing; we have also included a small factor for land for ancillary equipment and access roads. In the case of distributed solar photovoltaic, it was assumed that there is no land use impact because the units are mounted on the roofs of buildings. However, for Solar PV, land use impact is based on the area occupied by the solar arrays plus a small amount of land for ancillary equipment.

17. Water Use

Water use is calculated as the net water usage (withdrawals less returns). For biomass, water consumption includes water used for irrigation as well as water used in the fuel production process. For hydroelectric power, water use is based on evaporation from reservoirs. For processes that use steam to drive a turbine, water use is affected by the make-up losses in the boiler and turbine. Processes such as solar and wind use water only to clean the panels or turbines, which is relatively small compared to water use in other pathways.

18. Air Emissions

Air emissions are emissions of criteria air pollutants that are measured on an LCA basis. The construction of the conversion facility is not included in the analysis. Pollutants include SO_x, NO_x, organic chemicals and particulate matter (PM).

19. Solids Emissions

Solids emissions are measured on an LCA basis. The construction of the conversion facility is not included in the analysis. In the pathways where municipal solid waste (MSW) is combusted, the solid emissions are considered to be negative as there is a reduction in total waste by the incineration process. Mine tailings are included in the solid emissions metric.

20. Biodiversity

Biodiversity is an important and complex issue in resource project development. Biodiversity is a measure of variability in a given ecosystem. A final environmental metric that was considered is the impact of the energy resource on biodiversity.

Diversity can be measured in multiple ways, including:

- Genetic diversity - the sum of genetic information contained in individuals and in populations
- Species diversity - the number of biological organisms and their relative abundance
- Ecosystem diversity - the variety of habitats, biotic communities, landscapes and ecological processes

Resource development projects impact biodiversity through habitat destruction, degradation and fragmentation. Resource development can alter water flows, affect predator-prey relationships, reduce wildlife mobility, increase air and water pollution levels and introduce non-native species to the ecosystem. The assessment and management of resource development impacts are an integral part of sustainability practices that take place throughout the process of developing energy resources.

Alberta has adopted the Canadian Biodiversity Standards which include assessments of:

- Condition indicators - measure the susceptibility of biodiversity to change due to various pressures and identify changes in biological productivity, species richness, species at risk and species status
- Pressure Indicators – include:

- Industrial and residential development
- Habitat loss or fragmentation
- Environmental degradation
- Population growth
- Consumption
- Invasive species

- Response Indicators - actions taken to address pressures such as species or habitat conservation efforts

Biodiversity monitoring is undertaken in Alberta by the Alberta Biodiversity Monitoring Institute, a public-private partnership that monitors biodiversity in Alberta by measuring species diversity (plant and animal), non-native species, species at risk and the human footprint in Alberta.

Biodiversity is difficult to quantify in the same manner as the other metrics we have used in the Study because biodiversity attributes are highly location- and development-specific. In addition, development projects that could negatively affect biodiversity may be ameliorated through sustainability action plans specific to the project, such as species conservation plans. Therefore we have not included biodiversity assessment as a quantitative metric in this Study.

Qualitatively we can make the following observations regarding resource development and project development (see Table 4.2). Due to the complexity of this issue, these observations are high level in nature and not intended to be a comprehensive summary of biodiversity issues but rather a starting point for consideration of this topic.

Table 4.2
Biodiversity and Energy Pathways

Resource Pathway	Biodiversity Impact	Response
Coal – Open pit mine / thermal power plant	Significant due to habitat loss, environmental degradation from air and water emissions. Affects fresh water consumption.	Sustainability plans for mine site reclamation at mine life end.
Coal – Shaft mining / thermal power plant	Reduced as compared to open pit mining due to lower habitat loss	Sustainability plans for mine site reclamation at mine life end
Oil Conventional	Habitat loss, fragmentation and degradation from well pads and pipeline corridors	Sustainability plans for site reclamation at well life end. Species conservation plans and wildlife corridor projects to address fragmentation due to pipelines.
Bitumen Mined	Habitat loss, fragmentation and degradation from mines and tailings ponds. VOC and dust pollution. Affects fresh water consumption.	Sustainability plans for mine site reclamation at mine and tailing pond life end. Wildlife protection plans and wildlife corridors.
Bitumen – Thermal	Reduced as compared to open pit mining due to lower habitat loss and fragmentation.	Sustainability plans for mine site reclamation at mine and tailing pond life end. Wildlife protection plans and wildlife corridors.
Natural Gas	Habitat loss, fragmentation and destruction at well head sites and pipeline corridors	Wildlife protection plans and wildlife corridors. Site reclamation at end of well life.
Uranium – Open Pit	Significant due to habitat loss and environmental degradation	Sustainability plans for mine site reclamation at mine and tailing pond life end. Wildlife protection plans and wildlife corridors.
Uranium – Shaft Mining	Reduced as compared to open pit mining due to lower habitat loss	Sustainability plans for mine site reclamation at mine and tailing pond life end. Wildlife protection plans and wildlife corridors.
Uranium – Solution Leaching	Reduced as compared to open pit mining due to lower habitat loss. Concerns regarding ground water contamination	Sustainability plans for mine site reclamation at mine and tailing pond life end. Wildlife protection plans and wildlife corridors.

Resource Pathway	Biodiversity Impact	Response
Hydro - Reservoir	Significant due to habitat loss from reservoir construction and habitat degradation downstream of dam. Fresh water losses due to increased evaporation as compared to pre-dam building.	Dam removal at end of life and restoration of riparian habitat
Hydro – Run of River	Reduced as compared to reservoir based hydro as no reservoir is constructed and there is reduced impact on downstream water flows.	Design to minimize impact on aquatic wildlife.
Wind	Habitat fragmentation due to construction process and turbine pads Bird and bat species affected by turbines	Addressed via appropriate sustainability plans, i.e. species preservation plans during construction, siting studies to reduce impact on birds and bats
Solar	Minimal for distributed solar Habitat loss and fragmentation with large scale installations	Addressed via appropriate sustainability plans e.g. solar farm in Ontario with tall grass prairie installation
Biofuels	Habitat loss, fragmentation and degradation if uncultivated lands are brought under cultivation for crop production. Monoculture contributes to habitat degradation and species loss. Habitat degradation through pesticide, herbicide and fertilizer use degrades. Water use negatively impacts local water supply. Introduction of genetically modified species	Non-food and high yield crops reduce impact Improved farming and fuels process to reduce herbicide, pesticide, fertilizer and water use
MSW Incineration	Reduce size of municipal waste dumps Possible air pollution	Design with appropriate air emissions controls.

Resource Pathway	Biodiversity Impact	Response
Anaerobic Digestion	Improves biodiversity through reduction of manure quantity, reduction in methane emissions and positive impact on water quality from manure piles	
Geothermal	Habitat degradation during construction process of well heads and pads.	Addressed via appropriate sustainability plans i.e. species conservation plans during construction, wildlife corridors etc
Biofuels - Thermal	Sustainable use of wood waste, black liquor and agricultural waste has little impact on biodiversity	

Time Frames for the Study

Metrics are reported with the most up to date information available, in most cases, the data are from 2012. All pathways are based on currently available, commercial technology. Not all pathways are practiced in Alberta today. Developing technologies are addressed in the future scenarios.

Future Scenarios

New technologies being developed offer significant promise to increase the amount of energy that can be produced in Alberta. Many of these technologies are not commercial yet and their impact therefore is not captured in an assessment of energy available via current methods. For the Study, we assessed technology improvement as either incremental or breakthrough:

Incremental Technology Developments – Technology developments are expected in every resource sector, however, these developments will be incremental in nature. We considered research and development efforts that are currently underway as a basis for estimates of technology improvements. For example, there are efforts to improve currently available enzymes and yeasts to improve bioethanol yields and processing efficiencies. We considered how those improvements may affect bioethanol technology deployment.

Breakthrough Technology Development – Breakthrough technologies could be developed and implemented in every resource sector. For example, an entirely new class of enzymes would enable much more efficient biomass utilization and would therefore substantially increase the biomass energy available in the Province. In the bitumen resource sector, new technologies would enable much higher resource recovery from existing SAGD facilities at lower energy input. We considered elements of the resource pathways that represent the largest barrier to more extensive technology deployment and used engineering first principles to estimate the extent that a breakthrough technology could improve the availability of each resource.

Section 5.

Energy Resources and Pathways

Energy Resources and Pathways

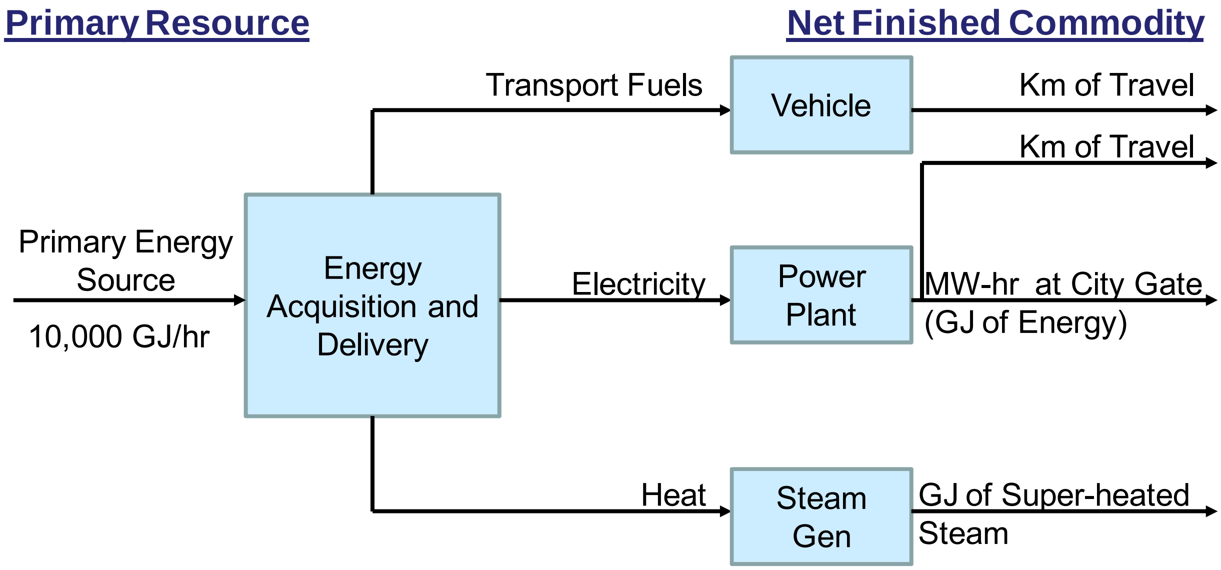
This section includes a discussion of each resource and pathway on a resource basis. The sections include a description of the resource base, the pathways currently practiced in Alberta, the pathways that are commercially available yet not practiced in Alberta, and the pathway metrics. The primary energy sources and commodity energy products were defined earlier and are shown here again in Table 5.1 to provide a simple schematic that summarizes the pathways from primary energy to commodities. We chose an arbitrary primary energy input of 10,000 GJ/hr simply to illustrate the conversion efficiency and commodity energy product yields for the same energy input from each of the primary sources.

Table 5.1.
Energy Resources and Commodities

Energy Resources	Electricity	Heat	Transport Fuels
Hydrocarbon based			
Coal	√	√	NA
Oil (including bitumen)	√	√	√
Natural Gas	√	√	√
Biologically based			
Crops – food crops and non-food crops	√	√	√
Forestry products	√	√	√
Waste material from crops and forestry	√	√	√
Manure	√	√	√
Non-hydrocarbon, Non-Bio based			
Hydroelectric power	√	NA	NA
Wind	√	NA	NA
Solar energy for electricity	√	NA	NA
Solar energy for heating	√	√	NA
Geothermal energy	√	√	NA
Landfill gas	√	√	√
Municipal Solid Waste	√	√	√
Nuclear	√	√	NA
Electricity to Transport and Heat			
Transport	NA	NA	√
Heating	NA	√	NA

NA: Not applicable

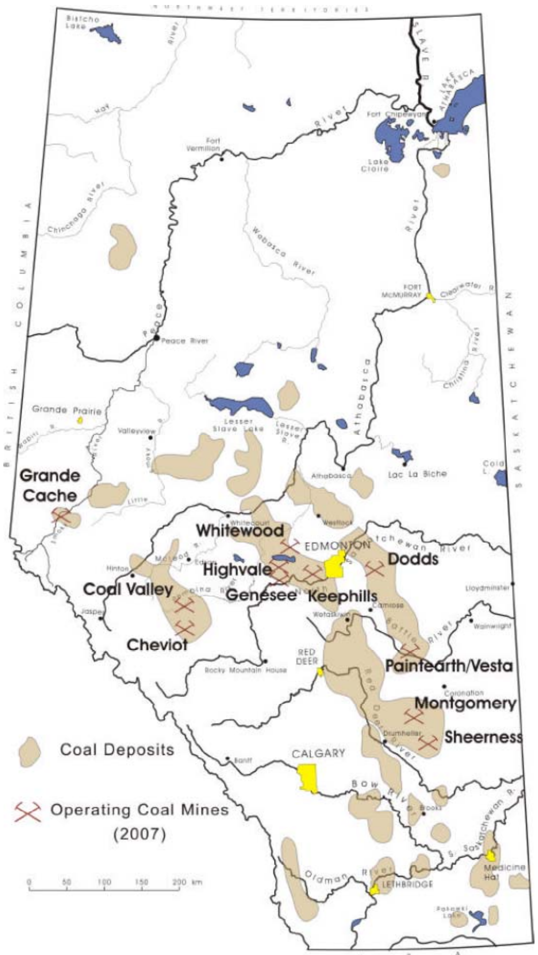
Figure 5.1
Pathways from Primary Energy to Finished Commodity



Coal

Coal is one of the major energy sources in Alberta. Around 70% of Canada's coal reserves are found in Alberta. (Energy, 2013) Almost half of the Province lies on top of coal deposits. Alberta coal is primarily produced via open-pit mining. Over 76% of the coal produced in Alberta is sub-bituminous; the rest is bituminous, of which 41% is bituminous metallurgical, which is not used as an energy source. (CanSim, 2012) All the sub-bituminous coal is used for electricity production, over 91% of the bituminous coal is exported; the rest is used in industrial process in Alberta for example to manufacture steel and cement. (CanSim, 2012) Most of the electricity is generated in mine mouth coal fired power plants that use sub-bituminous coal. (AMEC, 2006) Figure 5.2 shows a map of Alberta with existing coal reserves and coal mines. Table 5.2 shows the resource availability for coal in Alberta. (Alberta Energy Regulator (ERCB), 2013)

Figure 5.2
Alberta Coal Resources and Coal Mines



(CanSim, 2012)

Table 5.2
Alberta Coal Production and Reserves - 2012

	Heating Value	Coal		
	GJ/tonne	million tonnes	PJ/yr	PJ
Energy Produced (2012)		30	598	
Sub bituminous		22		
Bituminous Thermal		8		
Bituminous Metallurgical		5		
Reserves				
Established		33,000		790,135
Ultimate		620,000		
Heat content average for all coal	23.7			

Coal Production

Coal is produced from underground and surface mines. Coal is usually cleaned and sized at the mine in the beneficiation process before shipping to the end user. The steps in coal mining are shown in Figure 5.3 for surface and underground mining. The steps in beneficiation are shown in Figure 5.4.

Coal is transported in a number of ways:

- Conveyor – for distances of up to 10 km powered by electricity
- Diesel truck – generally for short distances
- Diesel train – main transport for coal in the US
- Ship or barge – long distance transport when water access is available

After delivery to the end user, coal is ground to the proper size.

Coal losses occur throughout the distribution chain: from coal left in the mine to support the roof in underground mining, to losses in separation of coal from non-coal waste rock at the mine, to losses in washing, losses in transport, and losses in sizing the coal. (Baryua, 2012) In one study for an efficient surface mine, coal losses were estimated to be 1.5%. (Confidential_Client, 2012)

Figure 5.3
Steps in Mining Coal

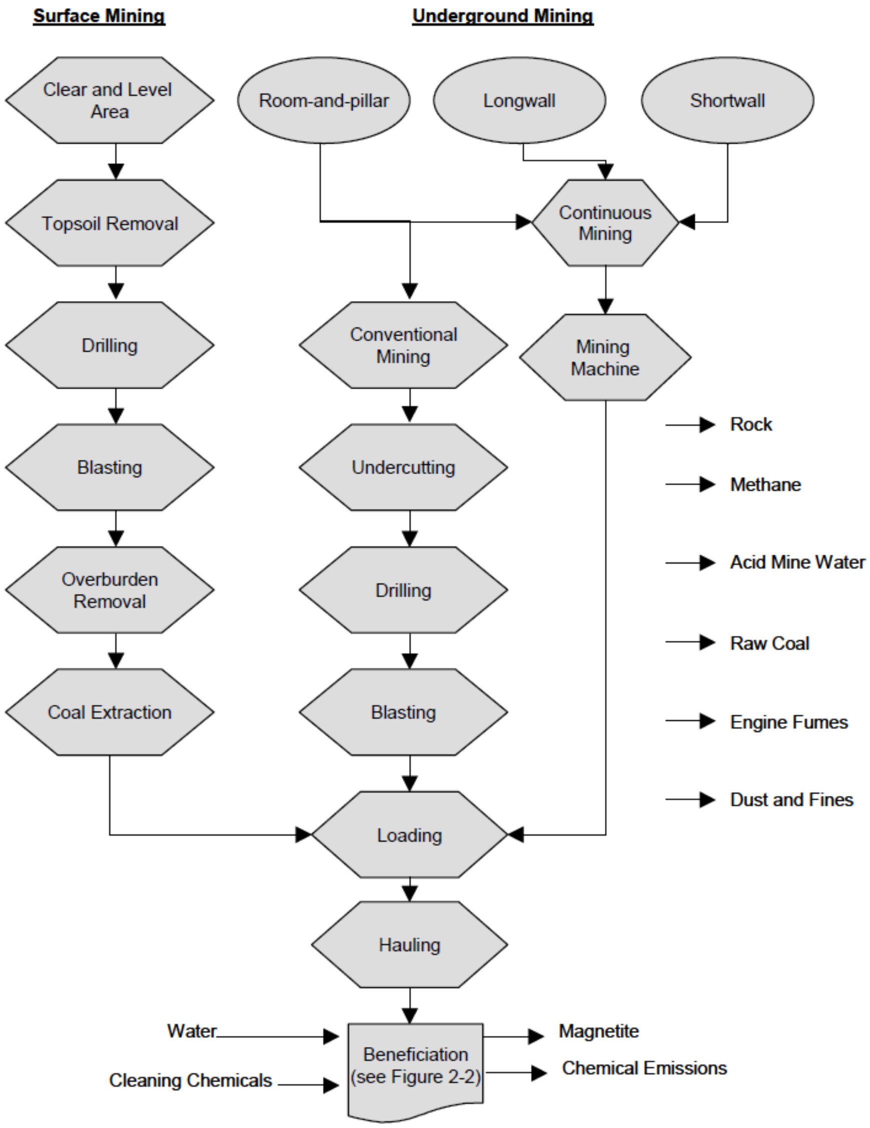
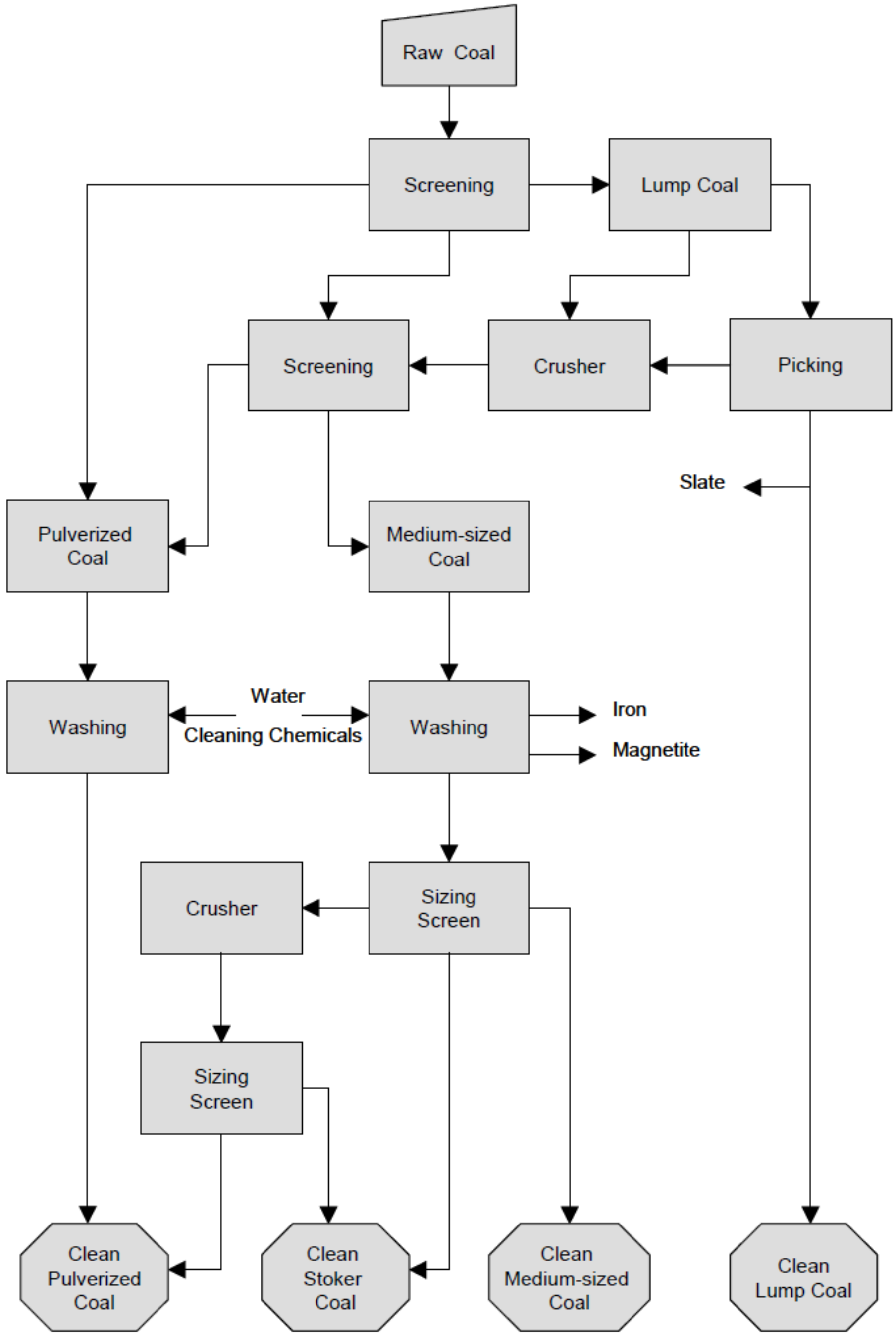


Figure 5.4
Coal Beneficiation



Magnetite is added to facilitate coal cleaning and is not a product of coal mining.

Coal Pathway Characterization

The pathway for coal includes:

- Mining
- Transport
- Sizing
- Power generation
- Flue gas treatment
- Power line losses

Figure 5.6 and Figure 5.7 show examples for typical pathways for sub-bituminous coal from mining through delivery of electricity at the city gate. Figure 5.6 shows the energy delivered from 10,000 GJ/hr of coal mined from surface mines, cleaned, sized, and delivered at mine mouth power plants with delivery of electricity to customers 500 km away on a 500 kV transmission line with 3.4% losses. Figure 5.7 includes the impact of CCS, which reduces the delivered electricity.

For these examples, we have assumed that the efficiency of electricity generation of the sub-critical power plants is 39% without CCS and 27% with CCS on an HHV basis. (NETL, Cost and Performance Baseline for Fossil Energy Plants, 2007), (NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2a, September 2013, 2013) In these examples, the city gate delivered electricity from 10,000 GJ/hr of coal is 977 MW without CCS and 669 MW with CCS.

Figure 5.6
Coal Pathway – Sub-bituminous without CCS

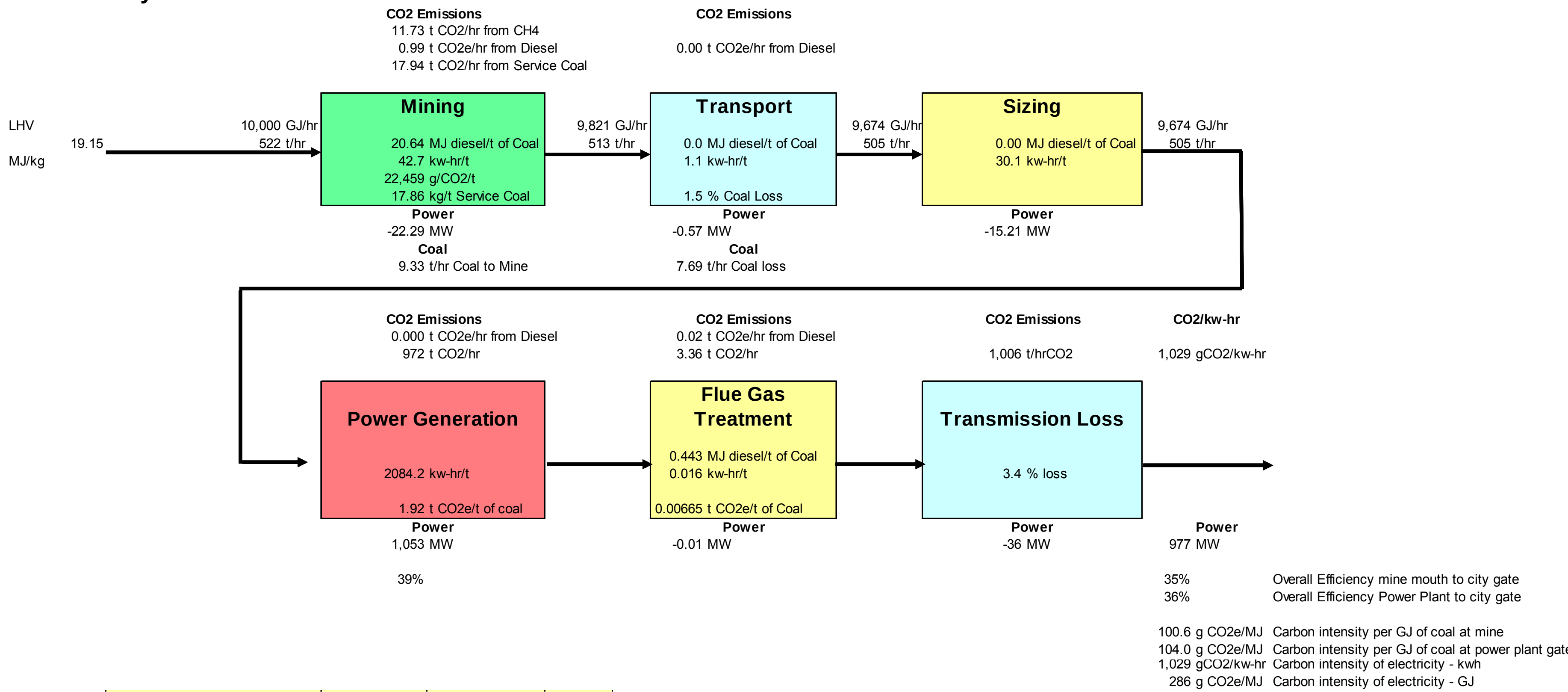
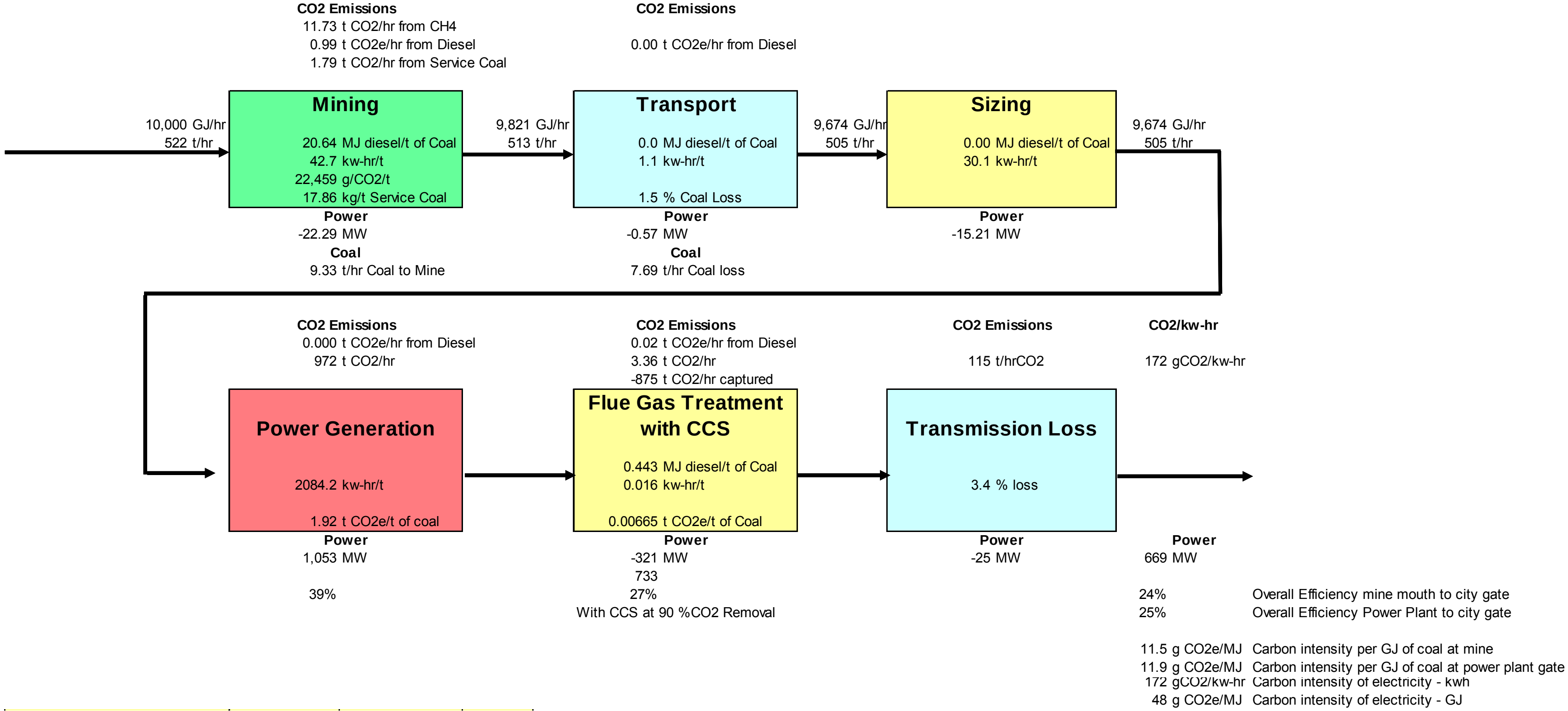


Figure 5.7
Coal Pathway – Sub-bituminous with CCS



Pathways for Delivering Commodity Energy from Coal

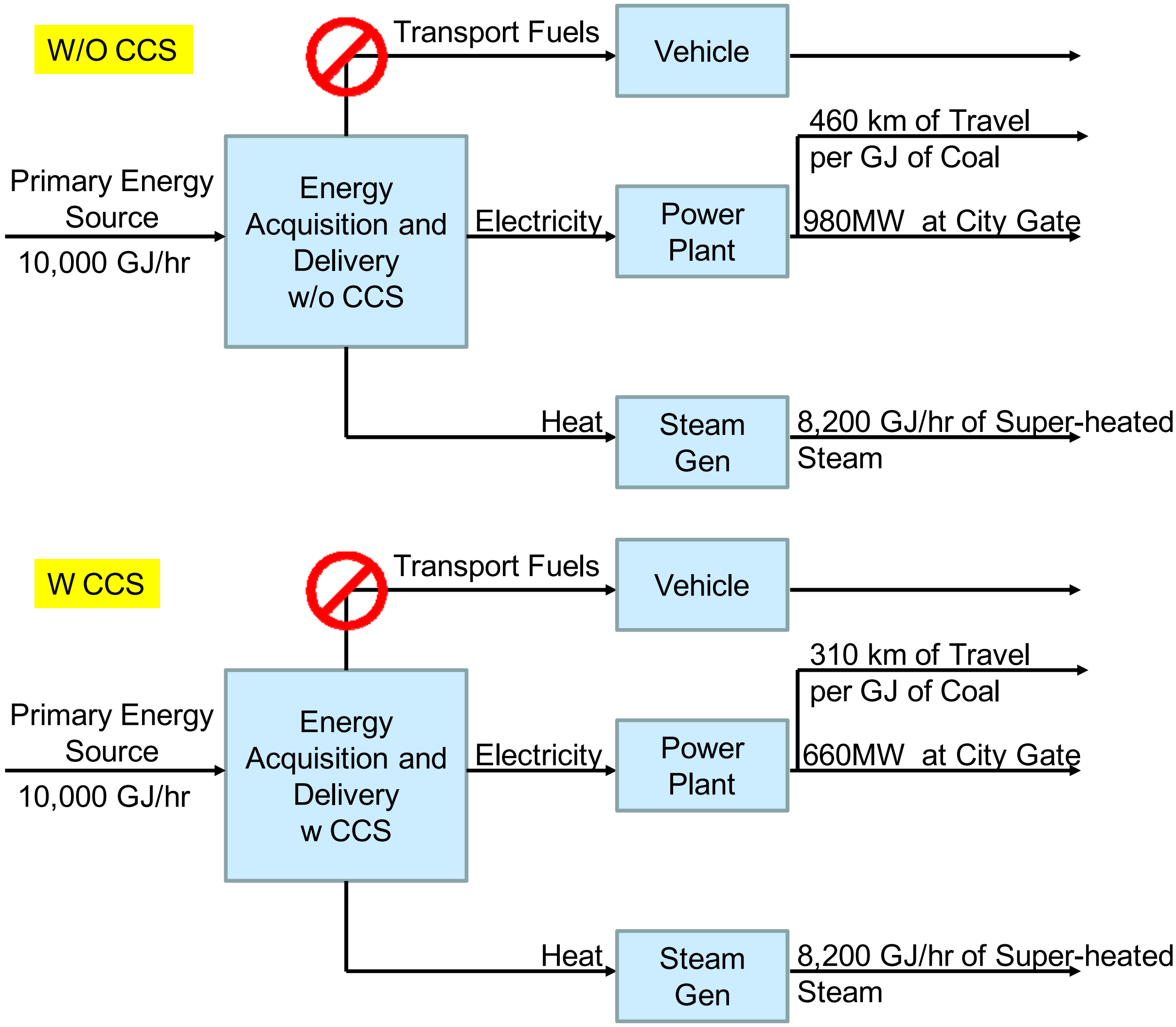
Table 5.3 summarizes the energy step down to convert an initial 10,000GJ/hr of coal to commodities of electricity or heat. Some of the power generated is consumed in mining and processing, as well as at the power plant for flue gas treatment and for CCS, if present.

Table 5.3
Energy Summary – Conversion of Coal to Electricity or Heat

Coal	Factors		Surface Mine No CCS	Surface Mine With CCS
Power from coal	Coal at mine	GJ/hr	10,000	10,000
Losses	Losses in beneficiation	GJ/hr	(179)	(179)
	Losses in transport	GJ/hr	(147)	(147)
	Sizing	GJ/hr	0	0
	Coal to electric power plant	GJ/hr	9,674	9,674
	Efficiency		39%	27%
	Line Loss		3.4%	3.4%
Commodity products				
Electricity				
	Power generated at power plant	MW	1,048	1,048
	Mining and Beneficiation	MW	(22)	(22)
	Transport	MW	(1)	(1)
	Grinding	MW	(15)	(15)
	Flue gas treatment	MW	(0.01)	(320.50)
	Power losses from CCS	MW		(322)
	Net Electric Power	MW	1,010	367
	Line loss	MW	(34)	(12)
	Electric power at city gate	MW	976	354
	Distance for electric vehicle	km/GJ	462	168
Heat		GJ/hr	8,223	8,223

The pathways for delivering commodity energy from coal without CCS and with CCS are summarized in Figure 5.8. We have assumed that coal is converted to electricity or to heat in a steam boiler. The distance that can be traveled on the electricity generated from coal is based on generating 35 kW-hr of electricity per GJ of coal in a plant using CCS and on the energy efficiency of a Nissan Leaf, which according to the US EPA ratings has an efficiency of 4.7 km/kW-hr. (EPA U. , 2012)

Figure 5.8.
Energy Pathways for Coal



A summary of the metrics for coal is shown in Table 5.4. The amount of each commodity produced and reserves shown in Table 5.4 and subsequent tables are from ERCB reports for 2012. Alberta demand for electricity is from AESO reports for 2012 and demand for tranpsoortation fuels is from CanSim for 2012.

Table 5.4
Coal Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Coal
Energy Type				
	Type of Source			Stock
Production and Capacity				
	Remaining Established Reserve Potential, Primary Source	PJ		790,100
	Annual Production of Energy from Primary Source			
	Actual Annual Production, Primary Source	PJ/yr		598
	Coal	MM MT/yr		29
	Available Commodity Production Capacity (Current Installed Capacity)			
	Commodity - Conventional Units			
	Electricity	MW		6,249
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr		Not Applicable
	Electricity	PJ/yr		200
	Current actual commodity produced			
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr	86	
	Electricity	GWh/yr	75,500	37,800
	Heat	PJ/yr	1,260	
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr	468	
	Electricity	PJ/yr	272	136
	Heat	PJ/yr	1,260	
	Available Commodity % of Alberta Consumption			
	Electricity	%		50
	Commodity Production if all Alberta Primary Source is Converted to Commodity			
	Commodity - Conventional Units			
	Electricity	GWh/yr		53,500
	Commodity - PJ/yr			
	Electricity	PJ/yr		192
	Heat	PJ/yr		510
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption			
	Electricity	%		71
	Heat	%		40

Table 5.4 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Coal
Energy Density of Energy Source				
	Primary Source (LHV)	MJ/kg		20.9
Efficiency and Energy Consumption				
	Energy Consumption			
	Electricity	GJ/GJ		1.84 - Existing Gen; 3.15 - New Gen with CCS
	Heat	GJ/GJ		0.22
	Net Energy Ratio			
	Electricity	GJ/GJ		0.21 - Existing Gen; 0.14 - New Gen with CCS
	Heat	GJ/GJ		0.70
	Electricity Conversion			
	Efficiency of power plant conversion	%		37.674 w/o CCS - current capacity; 26.082 for new capacity w CCS
	Electricity	kW-hr/GJ Primary Source		105 kw-hr/GJ of Coal - Existing Capacity: 72 kw-hr/GJ of Coal - New capacity with CCS
	Distance Delivered			
	Distance delivered from Electricity	km/GJ Primary Source		497 km/GJ of Coal - Existing Capacity: 341 km/GJ of Coal - New capacity with CCS
Environmental Metrics				
	GHG			
	Electricity	g CO2e/MJ		281
	Heat	g CO2e/MJ		120
	Land Use			
	Electricity	ha/PJ		0.045
	Heat	ha/PJ		0.019
	Water Use			
	Electricity	m3/GJ		0.58
	Heat	m3/GJ		0.205
	Air emissions			
	Electricity	g/MJ		5.7
	Heat	g/MJ		2.4
	Solids emissions			
	Electricity	g/MJ		34.0
	Heat	g/MJ		15.0

Technology Developments-- Coal

There are a number of areas where technology development will improve the utilization of coal resources.

Incremental Improvement— Incremental technologies will enable extension of the life of coal fired power plants by reducing GHG emissions. These technologies include increased co-firing of biomass, more efficient management of stack gas emissions and improved ash management, as well as improved management of the electrical transmission grid.

Breakthrough Technology— The most important technology to extend coal for electricity generation is the development of cost effective carbon capture and safe and effective storage of CO_2 that can address the public's concerns about long term CO_2 storage. These developments are occurring all over the world. However, inconsistent tax signals and legistlative policies coupled with low cost for other energy sources are delaying development and implementation of CCS technology.

Another potential breakthrough technology is in situ coal gasification with CCS, which is still too far in the future to be considered in this Study.

Crude Oil

Alberta supplies around 61-62% of the Canadian crude oil supply. (Cansim, Table 126-001 Supply and disposition of crude oil and equivalent, 2012) Imported crude oil accounts for about 19% of Canadian crude oil supply; the other provinces supply the rest.(ibid) Of the crude oil supplied by Alberta, conventional crude oil accounts for around 24% of Alberta supply, the rest is a roughly 50/50 mix of raw bitumen and synthetic crude oil. (ibid) Alberta exports around 80% of the crude oil it produces.(ibid)

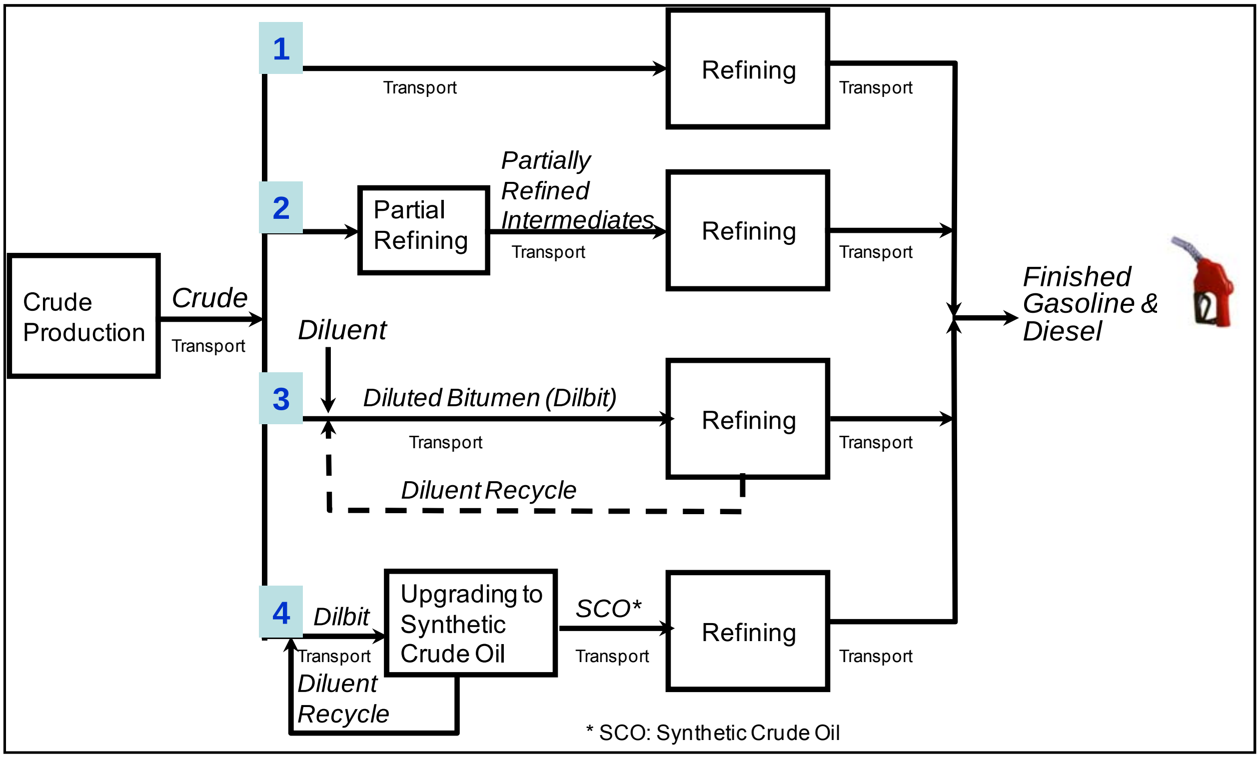
Alberta has significant reserves of conventional crude oil and bitumen. Crude oil production and the energy reserves for conventional crude oil and bitumen are sumarized in Table 5.5.

Table 5.5
Energy from Crude Oil

		Crude Oil and Bitumen	
		Bitumen	**Conventional Crude**
Energy Produced (2012)	mil m^3	114	32
Reserves			
Established	mil m^3	26,700	269
Ultimate	mil m^3	50,000	3,130
Heat content	GJ/m^3	39.6	36.5
Energy			
Energy Produced (2012)	PJ/yr	4,500	1,200
Reserves			
Established	PJ	1,058,000	10,000
Ultimate	PJ	1,982,000	114,000

Crude oil is converted to refined products via one of four pathways shown in Figure 5.9. In Path 1, crude oil is transported from the production site to the refinery and converted to finished products. In Path 2, crude oil is partially refined to intermediates, which are transported to a refinery to be converted to finished products. In Path 3, bitumen crude oil is mixed with a naphtha diluent and transported directly to the refinery. Diluent is then refined to finished products or recycled back to the bitumen production site. In Path 4, bitumen is mixed with a naphtha diluent and transported to an upgrader, and the resulting synthetic crude oil (SCO) is transported to the refinery for conversion to finished products.

Figure 5.9
Crude Oil Pathways to Finished Products



Oil Production

Oil production uses a range of technologies that depend on the reservoir type, extraction technology, and oil field equipment. Over the years, oil production has required progressively more intensive exploration, drilling, and collection activities. Early oil production activities involved identifying oil seeps and drilling relatively shallow wells. Today's oil exploration activities include sophisticated seismic technologies that detect underground (and in deep water) geological formations. Accessing the oil also has become more difficult. For example, Chevron, Devon, and Statoil have completed the Jack #2 well in the Gulf of Mexico, at a depth of over 20,000 feet under 7,000 ft of water. (Scandoil, 2006)

Petroleum production commonly is divided into three general methods of oil recovery: primary, secondary and tertiary.

- *Primary recovery* produces oil using the pressure of the oil reservoir. It may be enhanced by gas or water injection to maintain the reservoir pressure. A pump may be used to lift the crude, or gas lift may be used to increase oil recovery. The gas reinjected may be part of the associated gas or the CO_2 portion that is produced along with the crude oil, or it may be imported natural gas or nitrogen.

- *Secondary recovery* methods pump water into the reservoir to sweep trapped oil into collector wells. Secondary recovery often is the next step when production begins to decline during primary recovery. In many newer wells, water is injected from the beginning of production to better manage the reservoir and enhance ultimate oil recovery.
- *Tertiary recovery* methods use steam or CO_2 to reduce the viscosity of the oil and thereby increase production. Tertiary recovery is more energy intensive than primary and secondary recovery and generally is not practiced unless oil production by other means is no longer feasible. In the case of heavy crudes, especially in Canada, tertiary recovery using steam often is practiced from the beginning of production. Steam injection is used to recover heavy crudes in Venezuela, Russia, Egypt, Syria, in the central valley of California, and the Canadian provinces of Alberta and Saskatchewan.

The distinction between primary, secondary, and tertiary recovery is somewhat loose. Is it secondary recovery when water is used to repressure a reservoir? Is it tertiary recovery when CO_2 is removed from the associated gas and reinjected into the reservoir? If heavy oils and bitumen are produced by steam injection from the start of production, is this tertiary recovery?

Over time, reservoir pressure often decreases, gas production generally decreases although the gas to oil ratio may increase, water production often increases, and crude production generally decreases. In addition, it may be necessary to inject gas, water, or even nitrogen, CO_2 or steam to enhance oil recovery as reservoirs age

Beyond the oil reservoir conditions, handling of produced gases affects the GHG footprint of a crude oil. Fugitive emissions can be significant sources of GHG emissions resulting from leaks around casings or the type of oil production equipment used. Associated gas may be vented rather than flared. Flaring of gas is significant in some areas of the world and is not reported in a consistent manner. Research in Alberta showed 95% average flare efficiency in Alberta in conventional oil batteries for the early 2000s (Johnson). Flaring of gas, either as a means of disposal or as a safety measure, is the most significant source of air emissions from oil and gas installations. Even if continuous flaring ended, occasional burning of small amounts of gas will still be necessary for safety reasons. Alberta has extensive reporting of gas emissions and requires the conservation of economic gas streams.
(AER, 2013)

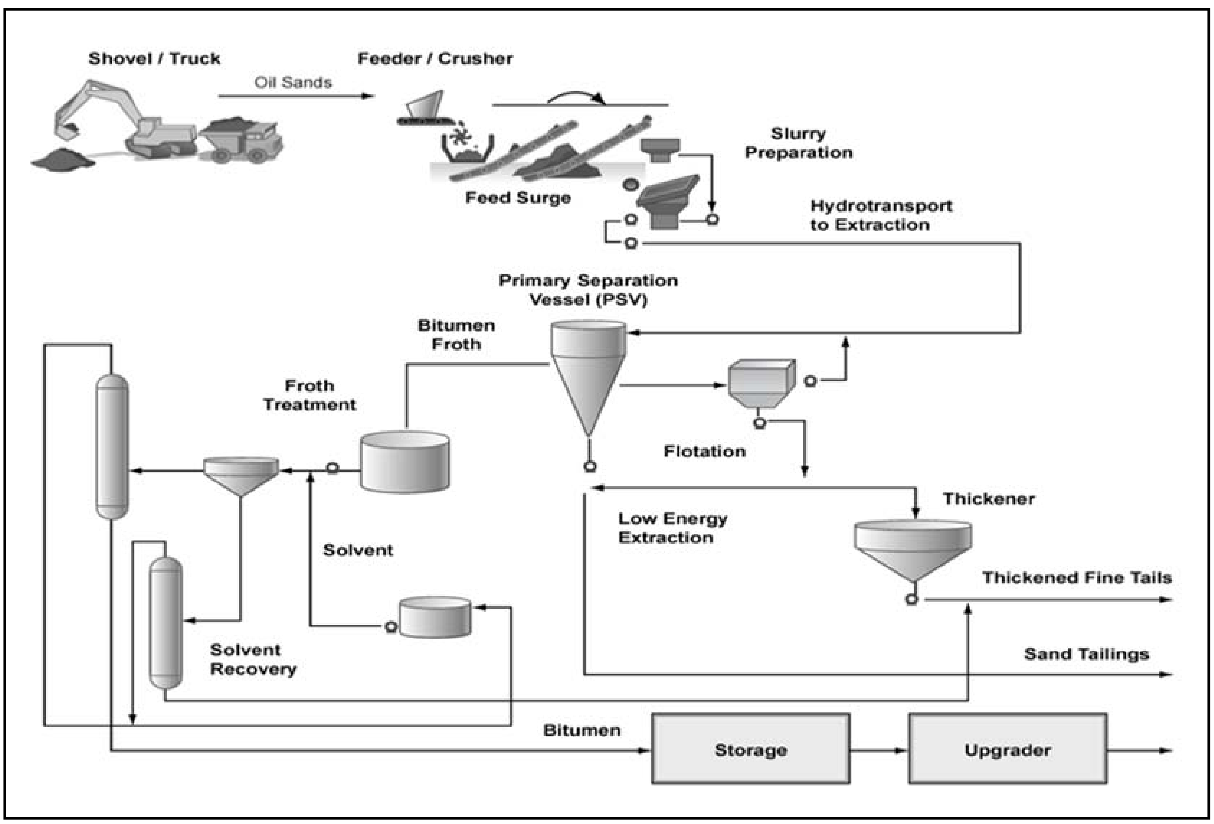
Alberta Crude Oil Production

Bitumen crude oil is produced in the Alberta oil sands region primarily by mining and by in situ methods.

Mining

Oil sand surface mining is by truck and shovel. The primary energy requirement for mining is diesel fuel to power the trucks; the shovels are often electric. On the surface, natural gas and electricity are used to separate bitumen from sand. Figure 5-10 is a flow scheme for bitumen from mining. Bitumen is separated from sand in a number of extraction steps using water with chemicals and naphtha. Fine sand particulates are rejected to tailings ponds. A small amount of bitumen and naphtha are lost to the tailings ponds. Bitumen from mining is mostly sent on to upgrading where it is converted to a lighter, bottomless synthetic crude oil. Newer bitumen-sand separation processes that use paraffin based naphtha can produce bitumen sufficiently low in residual sand particulates that it can be sent directly to refining, diluted with naphtha or SCO.

Figure 5.10
Oil Sand Mining



In Situ Production

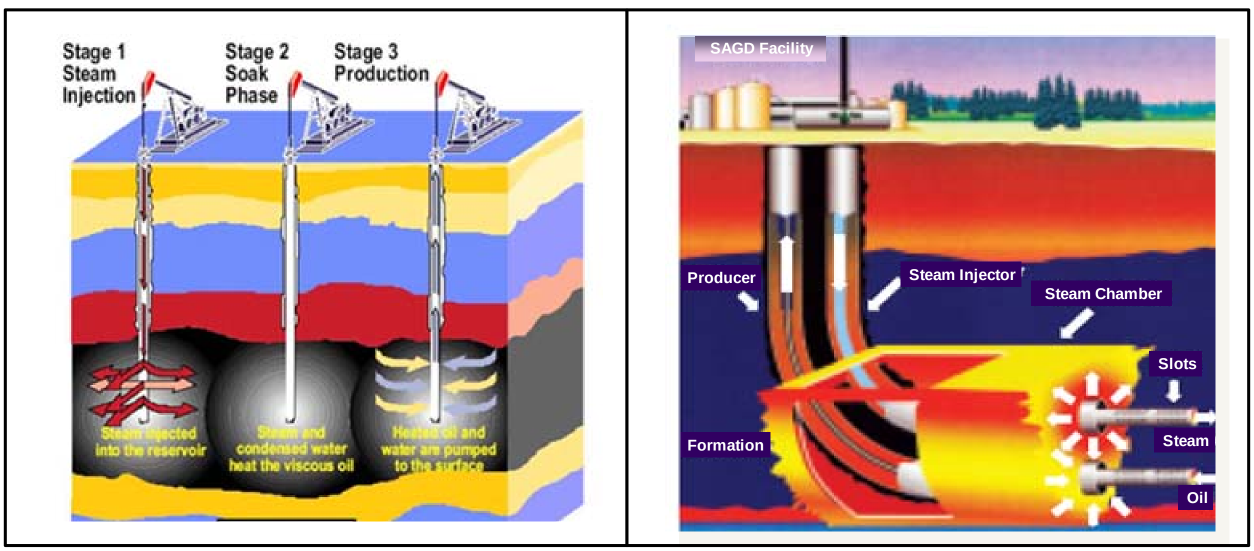
In situ processes include thermal and non-thermal production methods.

Thermal Methods

Thermal production in Alberta is by means of either cyclic steam stimulation (CSS) or steam assisted gravity and drainage (SAGD); schematics are shown in Figure 5.11. The primary energy requirement in thermal production is natural gas to generate steam for injection. The key parameter in determining energy intensity of SAGD is the steam-to-oil ratio (SOR), defined as barrels of cold water used for steam production per barrel of oil produced. On average, the SOR used in SAGD production of bitumen in Alberta has been around 2.9-3.1. (AER, 2012 etc.) However, the current trend in the industry is toward lower SOR and some producers are able to produce bitumen with an SOR as low as 2. (Cenovus, 2013) Industry average SOR may increase as reservoirs age and marginal ones are developed.

Figure 5.11
CSS and SAGD Schematics

CSS | **SAGD**



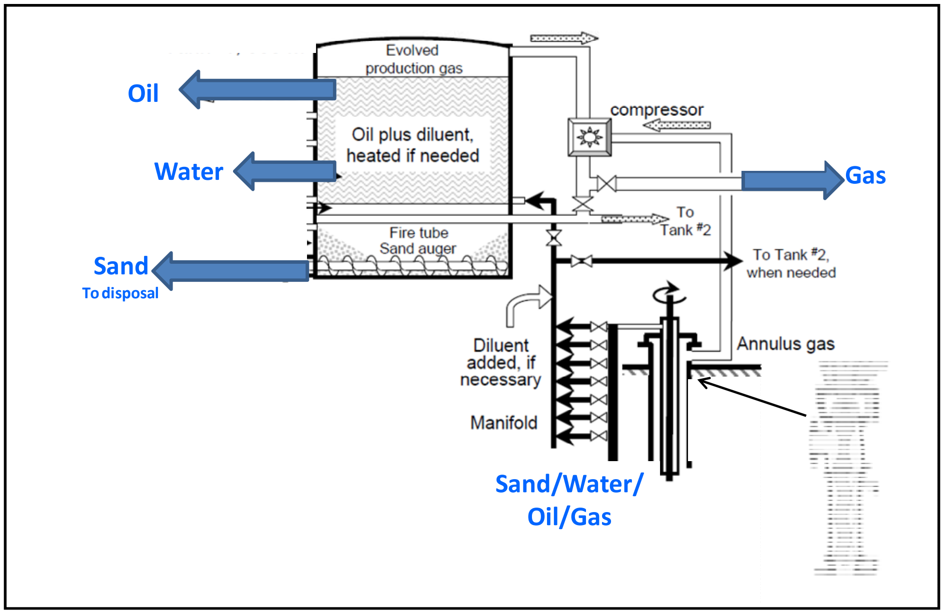
Other In Situ Production

Other in situ methods used for bitumen production are Cold Heavy Oil Production with Sand (CHOPS), Polymer Flood, and Solvent Injection (which may be utilized alone or in conjunction with steam injection).

Cold Heavy Oil Production with Sand (CHOPS)

The CHOPS process uses progressive cavity pumps to extract sand with the oil. Separation of sand from oil occurs in surface processing. Associated gas can be recovered, used to drive the production equipment, flared, or vented. A schematic of the CHOPS process for bitumen production is in Figure 5.13.

Figure 5.13
CHOPS Schematic

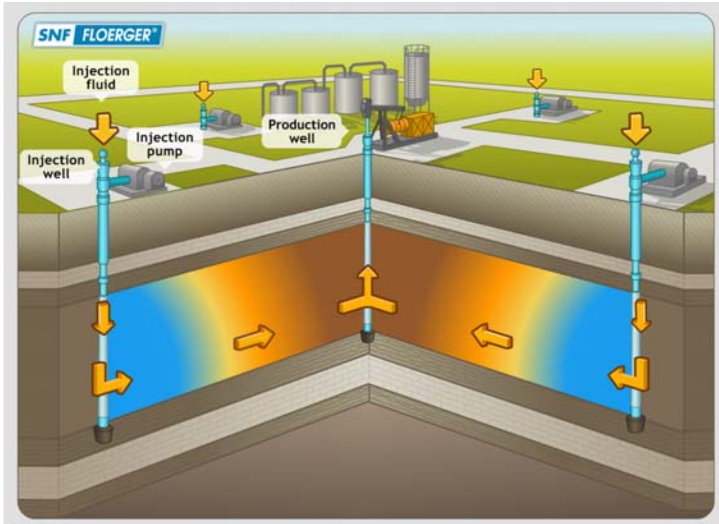


Polymer Flooding

In polymer flooding a polymer solution is added to the injected water to increase the effectiveness of water flooding. The polymer mixture moderates water breakthrough. In addition, the wetting characteristics of the water-oil-solid interface often are modified by chemicals added to the polymer solution.

Polymer flooding can result in a greater amount of oil recovery and a reduced rate of water consumption and production. (ADOE) Figure 5.14 shows a schematic of polymer flooding.

Figure 5.14
Polymer Flooding Schematic



Source: ADOE from Innovative Energy Technologies Program Annual Report, Alkaline Surfactant Polymer (ASP) Flood

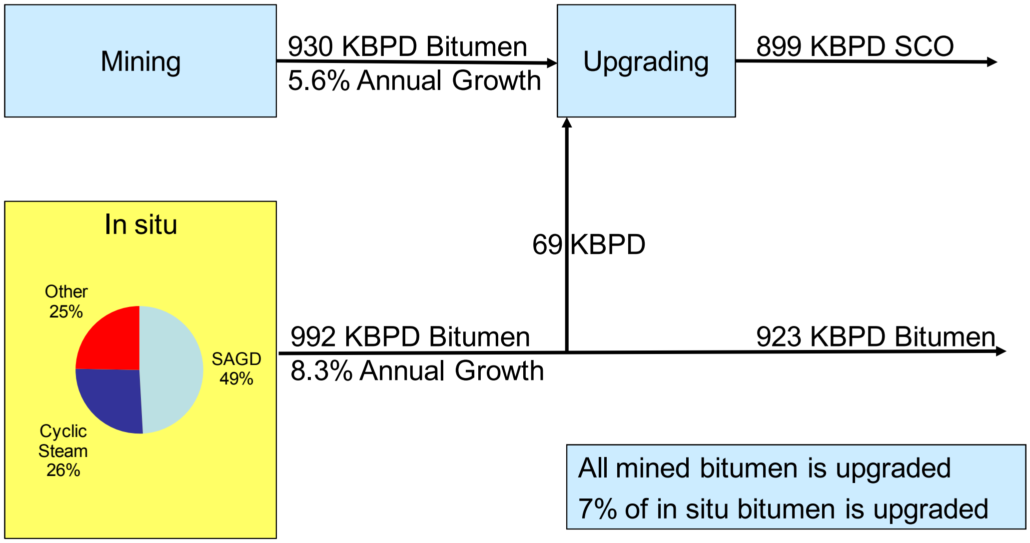
Solvent Injection

Hydrocarbon solvents may be injected into the oil reservoir to increase recovery. In Solvent Assist production, steam is injected, similar to SAGD, along with hydrocarbon solvent to reduce the SOR. Full Solvent production does not use steam and is similar to tertiary recovery. Use of solvents has been demonstrated in a commercial operation of bitumen production via CSS by Imperial (Boone, Wattenbarger, Clingman, & Dickson, 2011). Costs and recovery of solvents are the major barriers to this technology.

Bitumen Processing Routes in Alberta

The quantity of bitumen produced in 2012 and the disposition of bitumen is shown in Figure 5.15. (ERCB, 2013) The ERCB reports that in 2012 all the mined bitumen was upgraded to synthetic crude oil (SCO) in an upgrading facility; 7% of the bitumen produced via in situ methods was upgraded to SCO and the rest was sent to refineries diluted with either napthha or synthetic crude oil to meet the pipeline specifications of a maximum viscosity of 350 Centi-Stokes (cSt) at the pipeline reference temperature and a minimum gravity of 19 °API. The new Kearl oil sands mining operation (production began late April 2013) employes a proprietary froth treatment process and bitumen can be sent directly to refining without first upgrading. (Imperial Oil, 2013)

Figure 5.15
Alberta Bitumen Production and Disposition



Annual growth rates from ERCB ST98-13, 2012-2020

Upgrading

Upgrading and partial refining are intermediate steps in converting crude oils, including bitumen, into finished products. This intermediate step often is taken because the transportation system cannot handle a high-viscosity heavy crude oil, or because the downstream refinery cannot handle the high resid content of a heavy crude oil. The processing steps in bitumen upgrading are designed to convert bitumen to SCO that will be processed in a refinery to produce transportation fuels. Bitumen upgrading is done to reduce the viscosity and bottoms content of the SCO sufficiently that it can be shipped without diluent. Upgrading also reduces or eliminates the heavy residual material in SCO and reduces the sulfur content relative to bitumen.

Many of the upgraders in Alberta are based on coking, which converts much of the heavy resid to lighter products and also produces a solid petroleum coke product that contains the most refractory carbon. In Alberta, this petroleum coke is most commonly land-filled and not used as a fuel source. Other upgrading configurations are based on hydrogen addition and hydrocracking the resid using an ebulating bed hydrocracking unit. This processing option can yield higher volumes of SCO than coking and does not make a solid refractory carbon product, but does leave some residual material in the SCO and requires more hydrogen – generally from steam reforming of natural gas. Other upgrading configurations have been used; one upgrading plant uses a configuration based on thermal cracking and hydrogen addition via hydrocracking. Currently there are five bitumen upgrading facilities in Alberta with a capacity of over 1.3 MM barrels per day, Table 5.6. (ADOE, 2013) These facilities produce primarily synthetic crude oil.

A new 50,000 barrel per day upgrader is being developed near Edmonton, the Northwest Upgrader, which will convert diluted bitumen to low sulfur diesel fuel, naphtha, and low sulfur vacuum gas oil; CO_2 from processing will be captured for use in tertiary recovery of conventional oil. Future planned expansion of this new upgrader from 50,000 BPD to 150,000 BPD will take place in two phases later on. (The_Globe_and_Mail, 2013)

Table 5.6
Upgrading Capacity in Alberta

Project Name	Location	Capacity(bbl/d) Bitumen
Athabasca Oil Sands Project-Shell Scotford	Fort Saskatchewan	255,000
Suncor Base and Millennium	Fort McMurray	440,000
Syncrude Mildred Lake	Fort McMurray	407,000
Nexen Long Lake	Fort McMurray	72,000
Canadian Natural Resources Ltd Horizon	Fort McMurray	141,000
Total		1,315,000

Oil Refining

The processing steps in refining are designed to convert crude oil, SCO, or other intermediate feeds into finished products like gasoline, diesel, jet fuel, LPG, propylene, and fuel oil while also producing by-products like sulfur and petroleum coke. The yield of products depends on the properties of the crude oil and the refinery configuration.

The first step in refining is to fractionate the feed into major components: naphtha, distillate, gas oil, heavy gas oil, and residual oil (resid). Subsequent steps convert these streams into lighter components or treat them to improve their quality, for example, by removing sulfur and nitrogen, improving octane or cetane, or making other changes to enable maximum production of the most valuable products.

Alberta Refineries

There are four refineries operating in Alberta today. The capacities of these refineries are shown in Table 5.7: (ADOE, 2013)

Table 5.7
Current Refining Capacity in Alberta

Company	Location	Capacity(bbl/d)
Suncor	Edmonton	140,000
*Imperial Oil	Edmonton	187,200
Shell Canada	Scotford	100,000
**Husky Asphalt Refinery	Lloydminster	28,300
Total		455,500

*Refining feedstock is conventional oil. The other two refineries are configured to handle feedstock from oil sands.

**Husky has an asphalt refinery in Lloydminster, Alberta which produces asphalt products. Husky has an upgrader a short distance away in Lloydminster, Saskatchewan which produces synthetic crude oil (SCO) from heavy oil in the two provinces.

Alberta has the capacity to produce sufficient transportation fuels to meet provincial demand and exports approximately 20% of its refinery products. (Alberta Energy Regulator (ERCB), 2013)

Crude Oil Pathways

To determine the commodity energy that can be produced from crude oil, we used typical energy consumptions and yields for conventional crude oil, bitumen from in situ production and synthetic crude oil from mined bitumen. (Jacobs, 2012) For in situ production, we blended the energy consumption used in typical CSS, SAGD, and CHOPS according to the ratios shown in Figure 5.15, which are summarized as follows: 49% of in situ production is by SAGD, 26% of in situ production is by CSS, and the rest is primary production, of which CHOPS is one of the major production routes. For SAGD we assumed that bitumen was produced using a 2.5 steam to oil ratio (barrels of steam expressed as condensate per barrel of oil produced) with mechanical lift and on site generation of electricity. For CSS we assumed a steam to oil ratio of 4 and 80% steam quality. For CHOPS, we assumed that the energy consumption was primarily pumping energy. The methodology for estimating energy consumption in crude oil and bitumen production is found in our previous work (Jacobs, 2012).

Yields and energy consumption for converting crude oil and bitumen to refined products in a high conversion refinery are summarized in Figures 5.16 – 5.18.

Figure 5.16
Pathway for Converting Conventional Crude Oil to Commodity Energy

Conventional Crude Oil

10,000 GJ/hr
41,654 BPD

Crude Oil Production → Refining

Crude Produced	GJ/hr
Crude Oil	10,000
Total	10,000

Refinery Products	GJ/hr
C3	194
C4	146
MoGas	5,032
Diesel	3,495
Coke	626
Sulfur	40
Total	9,532

Products	Energy GJ/hr	Vol/Wt Yield		Miles per gallon
C3	194	1,243	BPD	
C4	146	829	BPD	
MoGas	5,032	23,470	BPD	26
Diesel	3,495	14,568	BPD	34
Coke	626	509	MTD	
Sulfur	40	104	MTD	
Total w/o sulfur	9,492			
MoGas + Diesel	8,527			
Energy Out/In	95%			
Transport Fuels Out/In	85%			
C3-C4	1%			
Coke	6%			

Energy Consumed from Well to Tank

Energy	Production GJ/hr	Transport GJ/hr	Refining GJ/hr	Transport GJ/hr
Internal Fuel Gas	419		541	
FCC Coke	0		559	
Electricity	0	3	88	
Natural Gas	22		425	
Diesel Fuel	0		0	54
Total	441	3	1,614	54

Energy	GJ/hr
Internal Fuel Gas	960
FCC Coke	559
Electricity	91
Natural Gas	447
Diesel Fuel	54
Total	2,111

Energy Consumed/In	21%	
Energy Import	10%	
Electricity Generation	39%	
Transmission loss	3.4%	
Net Electricity	37.7%	
Net Delivered Electricity	3,767	GJ/hr
Net Delivered Electricity	1,047	MW
Electricity per GJ of Energy In	105	kw-hr/GJ
Miles Delivered per GJ of Energy In	311	km/GJ

Commodity Energy Production		
Electricity	105	kw-hr/GJ
Heat	0.85	GJ/GJ
Distance	311	km/GJ

Figure 5.17
Pathway for Converting In Situ Bitumen to Commodity Energy

SAGD Bitumen Direct to Refinery

10,000 GJ/hr
38,067 BPD

	Crude Produced	GJ/hr	Diluent Recycle GJ/hr		Refinery Products	GJ/hr
Crude Oil Production	Crude Oil	10,000		Refining	C3	222
					C4	42
	Diluent	3,235			MoGas	5,028
					Diesel	3,089
					Coke	1,320
					Sulfur	88
	Total	13,235			Total	9,789

3,235 Diluent

Products	Energy GJ/hr	Vol/Wt Yield		Miles per gallon
C3	222	1,425	BPD	
C4	42	238	BPD	
MoGas	5,028	24,039	BPD	26
Diesel	3,089	12,916	BPD	34
Coke	1,320	1,074	MTD	
Sulfur	88	227	MTD	
Total - w/o sulfur	9,702			
MoGas + Diesel	8,117			
Energy Out/In	97%			
Transport Fuels Out/In	81%			
C3-C4	1%			
Coke	13%			

Energy Consumed from Well to Tank

Energy	Production GJ/hr	Transport GJ/hr	Diluent Transport GJ/hr	Refining GJ/hr	Transport GJ/hr
Internal Fuel Gas	34			618	
FCC Coke	0			689	
Electricity	0	4	1	95	
Natural Gas	1,051			806	
Diesel Fuel	0			0	55
Total	1,085	4	1	2,208	55

Energy	GJ/hr
Internal Fuel Gas	652
FCC Coke	689
Electricity	99
Natural Gas	1,857
Diesel Fuel	55
Total	3,353

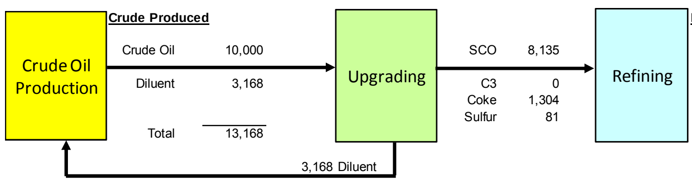
Commodity Energy Production	
Electricity	105 kw-hr/GJ
Heat	0.85 GJ/GJ
Distance	300 km/GJ

Energy Consumed/In	34%
Energy Import	20%
Electricity Generation	39%
Transmission loss	3.4%
Net Electricity	37.7%
Net Delivered Electricity	3,767 GJ/hr
Net Delivered Electricity	1,047 MW
Electricity per GJ of Energy In	105 kw-hr/GJ
Miles Delivered per GJ of Energy In	300 km/GJ

Figure 5.18
Pathway for Converting Mined Bitumen to Commodity Energy

Mined Bitumen to Upgrader - SCO to Refinery

10,000 GJ/hr
38,067 BPD



Crude Produced	GJ/hr
Crude Oil	10,000
Diluent	3,168
Total	13,168

Upgrading output	GJ/hr
SCO	8,135
C3	0
Coke	1,304
Sulfur	81

Refinery Products	GJ/hr
C3	113
C4	67
MoGas	5,116
Diesel	2,707
Coke	21
Sulfur	7
Total	8,032

Products	Energy GJ/hr	Vol/Wt Yield	Miles per gallon
C3	113	721 BPD	
C4	67	382 BPD	
MoGas	5,116	23,949 BPD	26
Diesel	2,707	11,323 BPD	34
Coke	1,325	1,078 MTD	
Sulfur	88	229 MTD	
Total w/o sulfur	9,328		
MoGas + Diesel	7,823		
Energy Out/In	93%		
Transport Fuels Out/In	78%		
C3-C4	0%		
Coke	13%		

Energy Consumed from Well to Tank

Energy	Production GJ/hr	Transport GJ/hr	Diluent Transport GJ/hr	Upgrading GJ/hr	Transport GJ/hr	Refining GJ/hr	Transport GJ/hr
Internal Fuel Gas	0			546		349	
FCC Coke	0			0		712	
Electricity	0	3	1	0	2	73	
Natural Gas	254			545		546	
Diesel Fuel	159			0		0	45
Total	413	3	1	1,092	2	1,679	45

Energy	GJ/hr
Internal Fuel Gas	895
FCC Coke	712
Electricity	79
Natural Gas	1,345
Diesel Fuel	204
Total	3,235
Energy Consumed/In	32%
Energy Import	16%
Electricity Generation	39%
Transmission loss	3.4%
Electricity	37.7%
Net Delivered Electricity	1,047 MW
Electricity per GJ of Energy In	105 kw-hr/GJ
Miles Delivered per GJ of Energy In	284 km/GJ

Commodity Energy Production	
Electricity	105 kw-hr/GJ
Heat	0.85 GJ/GJ
Distance	284 km/GJ

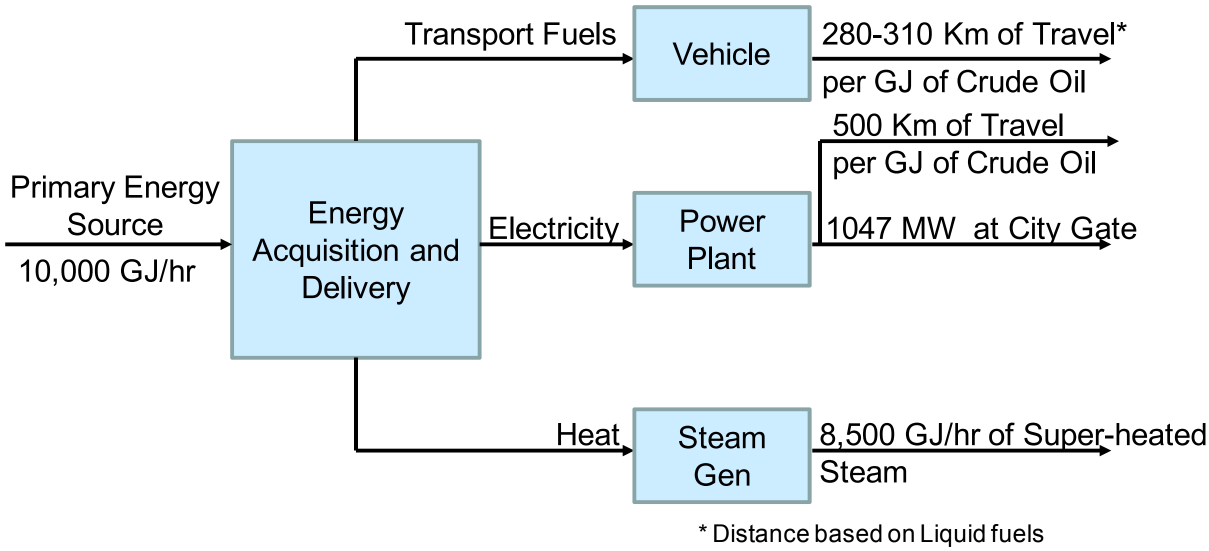
Table 5.8 summarizes the energy step down to convert an initial 10,000GJ/hr of conventional crude oil, in situ and mined bitumen to the commodity products: transportation fuels, electricity or heat.

Table 5.8
Energy Summary – Conversion of Crude oil to Gasoline and Diesel

Oil	Factors		Conventional Oil	In Situ Bitumen	Mined Bitumen
Crude oil	Oil produced at well	GJ/hr	10,000	10,000	10,000
Imported power	Natural Gas, Electricity, Diesel Fuel	GJ/hr	1,011	2,046	1,628
Total in		GJ/hr	11,011	12,046	11,628
Power consumed					
Crude oil production	Oil production processes	GJ/hr	(441)	(1,085)	(413)
Transportation	Crude and product transport	GJ/hr	(56)	(60)	(51)
Refining	Refining process	GJ/hr	(1,614)	(2,208)	(2,771)
Total	Net energy supplied from fuel gas, fuel oil, coke and imported natural gas and electricity	GJ/hr	(2,111)	(3,353)	(3,235)
	Supplied from crude oil	GJ/hr	(1,100)	(1,308)	(1,607)
Commodity products					
	Gasoline	GJ/hr	5,032	5,028	5,116
	Diesel	GJ/hr	3,495	3,089	2,707
Transportation (gasoline + diesel)	Refining process	GJ/hr	8,527	8,117	7,823
	Distance from spark and compression ignition engine vehicles	km/GJ of oil	316	299	287
Electricity	Generation efficiency of: 39%, line loss of 3.4%	GJ/hr	3,767	3,767	3,767
	Electric power	MW	1,047	1,047	1,047
	Distance for electric vehicle	km/GJ of oil	495	495	495
Heat		GJ/hr	8,500	8,500	8,500

The production of commmodity energy products from conventional crude oil and bitumen are summarized in Figure 5.19.

Figure 5.19
Energy Pathway – Conventional Crude Oil and Bitumen



The metrics for conventional crude oil and bitumen are summarized in Table 5.9.

Table 5.9
Oil Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Conventional Crude	Bitumen Mined	Bitumen In Situ	Total Oil
Energy Type							
	Type of Source			Stock	Stock	Stock	Stock
Production and Capacity							
	Remaining Established Reserve Potential, Primary Source	PJ		9,700.0	209,639	848,461	1,058,100.0
	Annual Production of Energy from Primary Source						
	Actual Annual Production, Primary Source	PJ/yr		1,270	2,140	2,281	5,691
	Oil and Bitumen	MM Bbls/yr		210	340	360	910
	Available Commodity Production Capacity (Current Installed Capacity)						
	Commodity - Conventional Units						
	Transportation Fuels	MM Bbls/yr					127
	Electricity	MW		nil	nil	nil	nil
	Heat	PJ/yr		nil	nil	nil	nil
	Commodity - PJ/yr						
	Transportation Fuels	PJ/yr					696
	Electricity	PJ/yr		nil	nil	nil	nil
	Heat	PJ/yr		nil	nil	nil	nil
	Current actual commodity produced						
	Commodity - Conventional Units						
	Transportation Fuels	MM Bbls/yr	86	not applicable	not applicable	Not applicable	127
	Electricity	GWh/yr	75,500	nil	nil	nil	nil
	Heat	PJ/yr	1,260	nil	nil	nil	nil
	Commodity - PJ/yr						
	Transportation Fuels	PJ/yr	468				696
	Electricity	PJ/yr	272	nil	nil	nil	nil
	Heat	PJ/yr	1,260	nil	nil	nil	nil
	Available Commodity % of Alberta Consumption						
	Transportation Fuels	%					148
	Electricity	%		nil	nil	nil	nil
	Heat	%		nil	nil	nil	nil
	Commodity Production if all Alberta Primary Source is Converted to Commodity						
	Commodity - Conventional Units						
	Transportation Fuels	MM Bbls/yr		190	320	350	860
	Electricity	GWh/yr		133,000	225,000	239,000	594,000
	Heat	PJ/yr		1,080	1,820	1,940	4,840
	Commodity - PJ/yr						
	Transportation Fuels	PJ/yr		1,170	2,020	2,210	5,400
	Electricity	PJ/yr		480	810	860	2,140
	Heat	PJ/yr		1,080	1,820	1,940	4,840
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption						
	Transportation Fuels	%		149	252	275	677
	Electricity	%		177	298	317	788
	Heat	%		86	144	154	384

Table 5.9 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Conventional Crude	Bitumen Mined	Bitumen In Situ	Total Oil
Energy Density of Energy Source							
	Primary Source (LHV)	MJ/kg		44.4	39.2	39.2	40.3
Efficiency and Energy Consumption							
	Energy Consumption						
	Transportation Fuels	GJ/GJ		0.25	0.41	0.41	0.37
	Electricity	GJ/GJ		1.78	1.77	1.98	1.86
	Heat	GJ/GJ		0.23	0.23	0.32	0.27
	Net Energy Ratio						
	Transportation Fuels	GJ/GJ		0.70	0.59	0.61	0.62
	Electricity	GJ/GJ		0.22	0.22	0.20	0.21
	Heat	GJ/GJ		0.68	0.69	0.61	0.66
	Electricity Conversion						
	Efficiency of power plant conversion	%		39	39	39	39
	Electricity	kW-hr/GJ Primary Source		105	105	105	104
	Distance Delivered						
	Distance delivered from Electricity	km/GJ Primary Source		500	500	500	500
	Distance delivered from Transportation Fuels	km/GJ Primary Source		310	280	300	290
Environmental Metrics							
	GHG						
	Transportation Fuels	g CO2e/MJ		89.7	102.8	100.5	99.0
	Electricity	g CO2e/MJ		205	233	237	228
	Heat	g CO2e/MJ		91.0	103.0	105.0	101.0
	Land Use						
	Transportation Fuels	ha/PJ		0.0033	0.0012	0.0003	0.0013
	Electricity	ha/PJ		0.0080	0.0029	0.0008	0.0032
	Heat	ha/PJ		0.0036	0.0013	0.0004	0.0014
	Water Use						
	Transportation Fuels	m3/GJ		0.005 - 0.22	0.10	0.008 -0.031	0.005-0.104
	Electricity	m3/GJ		0.37	0.37	0.37	0.37
	Heat	m3/GJ		0.005 - 0.22	0.10	0.008 -0.031	0.005-0.104
	Air emissions						
	Transportation Fuels	g/MJ		Not available	Not available	Not available	Not available
	Electricity	g/MJ		Not available	Not available	Not available	Not available
	Heat	g/MJ		Not available	Not available	Not available	Not available
	Solids emissions						
	Transportation Fuels	g/MJ		Not available	Not available	Not available	Not available
	Electricity	g/MJ		Not available	Not available	Not available	Not available
	Heat	g/MJ		Not available	Not available	Not available	Not available

Technology Developments – Oil

Incremental Improvement— Technology improvements are focused on improving efficiencies along all steps in the production path. In addition, producers are looking to minimize water consumption without increasing energy consumption. For in situ bitumen, producers are looking for incremental improvements to use less energy, which is primarily focused on reducing the steam to oil (SOR) ratio. For mined bitumen, producers are implementing paraffinic froth treatment to decouple mining from upgrading and enable bitumen from mining to be handled like bitumen from in situ production.

Breakthrough Technology— Breakthroughs in bitumen production include new in situ production methods that use alternatives to steam such as polymers, CO_2, solvents, or electricity to recover bitumen from the oil sands reservoir. Technologies are under development to enable bitumen recovery from carbonate formations. Partial upgrading technologies are being developed to enable more economical bitumen upgrading in Alberta and to reduce the need for diluent in transporting bitumen. These partial upgrading routes do not upgrade bitumen to the same extent as the current upgrading routes and the resulting sour synthetic crude oil likely will have a different market than the sweet synthetic crude oil that is currently produced.

Other break through techologies are the development of solvent aided bitumen recovery methods – especially for the marginal areas in the Carbonate Triangle region situated between the three major bitumen areas, Athabasca, Cold Lake and Peace River, in situ upgrading of bitumen, and the production of value added chemicals from bitumen and crude oil in Alberta. Future restrictions on GHG emissions may require oil sands producers to use CCS to reduce CO_2 emissions from bitumen production.

It is likely that Alberta will see future growth in the production of tight oil from shale formations, much as these resources continue to be developed in the US. The long term implications of greater production of tight oil in Alberta are expected to be signficant.

Other technologies outside of the crude oil pathways that will improve the efficiency of crude oil and bitumnen consumption are focussed on improving vehicle efficiency. In additon, other changes in refined product demand are likely to reduce the ratio of gasoline to diesel consumption which in turn will affect refinery configuration and the energy and GHG required to produce transportation fuels for the evolving transport vehicle pool.

Natural Gas

Natural gas is composed of methane and small proportions of heavier molecules such as ethane, propane, and butane and higher hydrocarbons. These heavier components are extracted from the gas produced at the well and sold as natural gas liquids. The term “wet gas,” used in the gas industry, refers to natural gas that has not been processed to remove ethane, propane, butane and “natural gasoline;” “dry gas” refers to natural gas after removal of these heavier components. The heavier components collectively are known as natural gas liquids (NGLs).

Natural gas may be classified into two types:

- Associated gas - a natural gas byproduct of oil production
- Non-associated gas – natural gas developed as the primary product from reservoirs that do not contain oil

While associated gas, also called produced gas, is an important source, the majority of gas production is non-associated. (MIT, 2011)

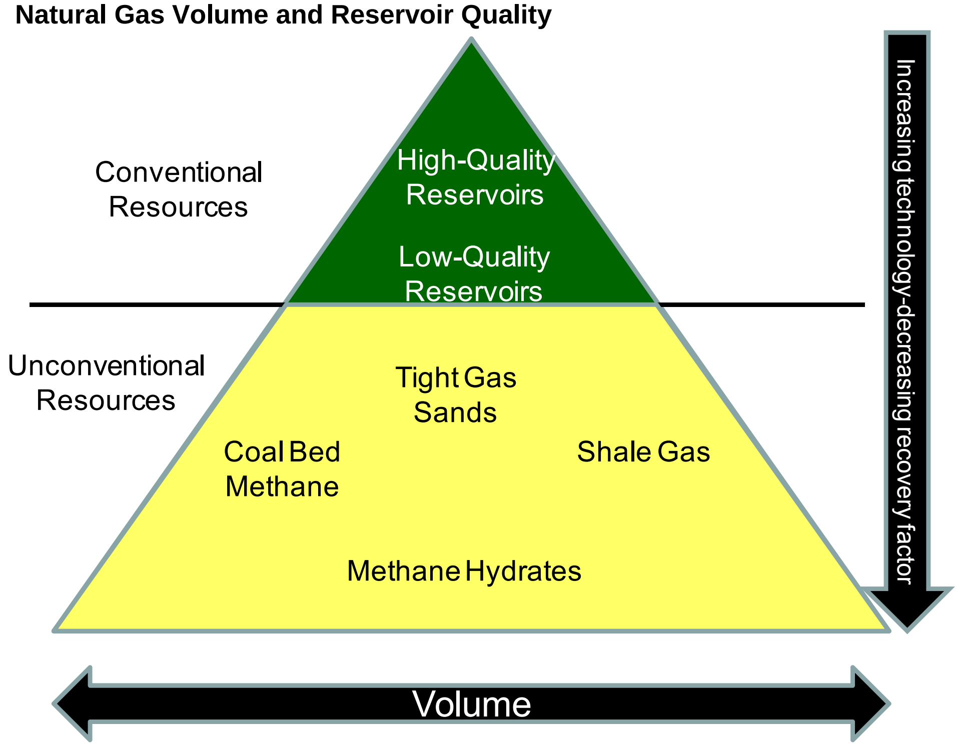
Non-associated gas is produced from wells drilled into a gas-bearing geological formation. Recovery is a result of controlled expansion of gas from the high pressure reservoir to lower pressure at the surface. Gas recovery from conventional, good-quality gas reservoirs, for example, with a 4,000 psi differential pressure between the reservoir and the surface facilities, can be as high as 80% of the gas in place. In contrast, typical recovery of oil in place from conventional wells is on the order of 30% to 40% after primary and secondary recovery are complete. (MIT, 2011)

Natural gas is found in different types of formations. Figure 5.20 illustrates a general principle of natural gas production. Much of the highest quality gas (high pressure, easy to recover) is in high quality formations. However, there is more gas potentially available in lower quality reservoirs and formations from which it is more difficult to extract the gas. In particular, a very large quantity of natural gas potentially could be available from methane hydrates, but requiring considerable technology development and effort.

- Conventional resources exist in discrete, well-defined subsurface accumulations (reservoirs), with permeability values greater than a specified lower limit. Such conventional gas resources can usually be developed using vertical wells, and generally yield the high recovery factors described above.

- By contrast, unconventional resources are found in accumulations where permeability is low. Such accumulations include "tight" sandstone formations (tight gas), coal beds (coal bed methane or CBM) and shale formations (shale gas).
- Unconventional resource accumulations tend to be distributed over a larger area than conventional accumulations and usually require advanced technology such as horizontal wells or artificial stimulation in order to be economically productive. Recovery factors from unconventional reservoirs tend to be much lower than from conventional reservoirs— typically on the order of 10% to 20% of gas initially in place with future pad drilling exposing up to 30% of gas initially in place.

Figure 5.20
Natural Gas Volume and Reservoir Quality

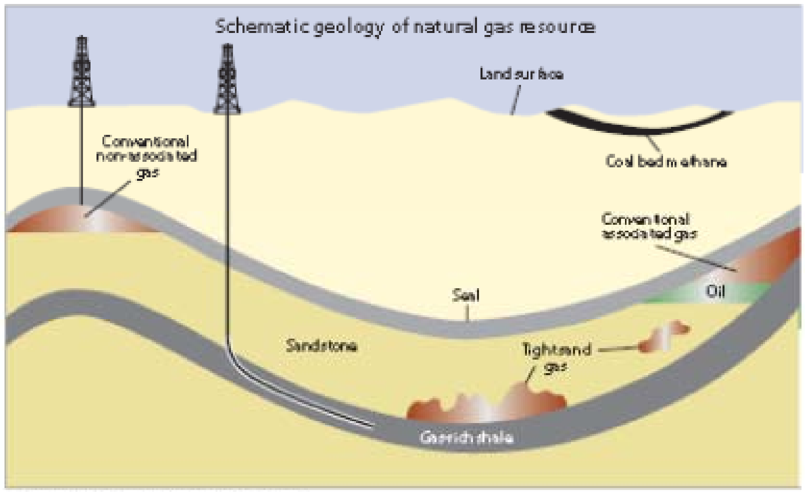


- Conventional reservoirs are of higher quality because they have high permeability and require less technology for development and production.
- Unconventional reservoirs are more abundant in terms of gas initially in place but have lower permeability and therefore require advanced technology for production and typically have lower recovery factors than conventional reservoirs.

From (MIT, 2011)

Conventional reservoirs are of higher quality because they have high permeability and require less technology for development and production. Unconventional reservoirs are more abundant in terms of gas initially in place but have lower permeability and therefore require advanced technology for production and typically have lower recovery factors than conventional reservoirs. The various resource types are shown schematically in Figure 5.21.

Figure 5.21
Natural Gas Reservoir Types



Source: U.S. Energy Information Administration

There is significant and complex cross-dependency between geology, technology and economics of natural gas production, which requires the use of unambiguous terminology when discussing natural gas supply.

Alberta Natural Gas Production

Alberta produces over 73% of Canada's marketable natural gas supply. (CanSim, Statistics Canada, 2012) This natural gas is used to supply energy for electricity generation and heat for industrial, business, and residential use. The steps in production of natural gas from conventional reservoirs are:

- Drilling and completion of production wells
- Recovery of a natural gas, natural gas liquids (NGLs), water from a multiphase mixture that is under pressure
- Separation of hydrocarbons and water
- Removal of acid gas (hydrogen sulfide, carbon dioxide) as necessary, depending on the specific reservoir gas composition
- Separation of "wet gas" into dry natural gas and gas liquids, often through the use of cryogenics
- Recompression of natural gas (mostly methane) for distribution to various consumers

- Transport of the recovered gas liquids (ethane, propane, butanes, natural gasoline) via rail car and pipeline for petrochemical, refinery, and heating uses.

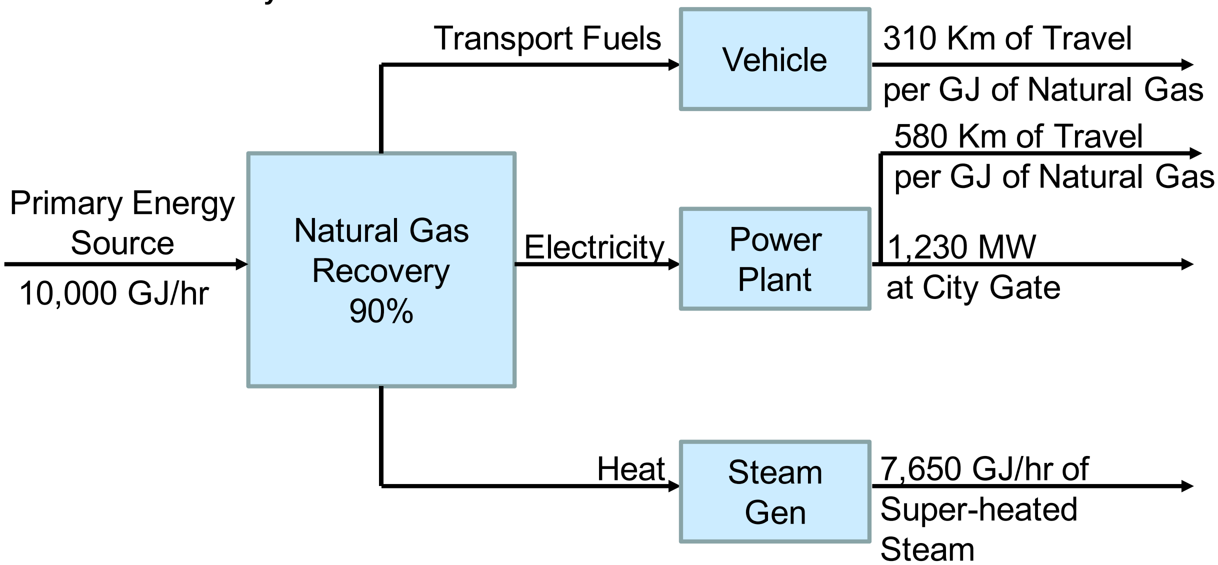
In Alberta, much of conventional natural gas production involves the use of "straddle plants," which separate methane from gas liquids, with product ethane targeted for Alberta's petrochemical producers.

Table 5.10 illustrates the energy step down to convert an initial 10,000GJ/hr of natural gas into the commodity products of transportation fuels, electricity or heat. The pathways for converting natural gas to commodity energy are summarized in Figure 5.22. We have assumed that 90% of the primary source natural gas is recovered as marketable gas (dry gas reservoirs). We assume electricity generation efficiency is 51% for a combined cycle plant, electricity transmission losses are 3.4%, and the fuel efficiency of natural gas in spark ignition engines is the same as gasoline on an equivalent heating value basis.

Table 5.10
Energy Summary – Conversion of Natural Gas to Transportation Fuel, Electricity and Heat

Natural Gas	Factors		Natural Gas
Power from natural gas	Natural gas from well	GJ/hr	10,000
Imported power	Natural Gas, Electricity, Diesel Fuel	GJ/hr	0
Losses	Loss of 10% from well to city gate	GJ/hr	(1,000)
Total power in		GJ/hr	9,000
Commodity products		GJ/hr	
Transportation	Substitute for gasoline	GJ/hr	9,000
	Spark ignition engines	km/GJ of gas	310
Electricity	Generation efficiency of: 51% - Combined Cycle & line loss of 3.4%	GJ/hr	4,434
	Electric power	MW	1,230
	Distance for electric vehicle	km/GJ	580
Heat		GJ/hr	7,650

Figure 5.22
Natural Gas Pathway



The metrics for natural gas are shown in Table 5.11.

Table 5.11
Natural Gas Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Natural Gas
Energy Type				
	Type of Source			Stock
Production and Capacity				
	Remaining Established Reserve Potential, Primary Source	PJ		35,200
	Annual Production of Energy from Primary Source			
	Actual Annual Production, Primary Source	PJ/yr		3,936
	Natural Gas	Billion scfd		10
	Available Commodity Production Capacity (Current Installed Capacity)			
	Commodity - Conventional Units			
	Electricity	MW		5400
	Heat	PJ/yr		1,237
	Commodity - PJ/yr			
	Electricity	PJ/yr		170
	Heat	PJ/yr		1,237
	Current actual commodity produced			
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr	86	
	Electricity	GWh/yr	75,500	26,700
	Heat	PJ/yr	1,260	1237
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr	468	
	Electricity	PJ/yr	272	96
	Heat	PJ/yr	1,260	1,237
	Available Commodity % of Alberta Consumption			
	Electricity	%		35
	Heat	%		98
	Commodity Production if all Alberta Primary Source is Converted to Commodity			
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr		780
	Electricity	GWh/yr		538,600
	Heat	PJ/yr		3,346
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr		3,936
	Electricity	PJ/yr		1,939
	Heat	PJ/yr		3346
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption			
	Transportation Fuels	%		566
	Electricity	%		714
	Heat	%		266

Table 5.11 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Natural Gas
Energy Density of Energy Source				
	Primary Source (LHV)	MJ/kg		47.1
	Primary Source (HHV)	MJ/kg		52.2
Efficiency and Energy Consumption				
	Energy Consumption			
	Transportation Fuels	GJ/GJ		0.1
	Electricity	GJ/GJ		1.22
	Heat	GJ/GJ		0.31
	Net Energy Ratio			
	Transportation Fuels	GJ/GJ		0.82
	Electricity	GJ/GJ		0.28
	Heat	GJ/GJ		0.62
	Electricity Conversion			
	Efficiency of power plant conversion	%		51
	Electricity	kW-hr/GJ Primary Source		123
	Distance Delivered			
	Distance delivered from Electricity	km/GJ Primary Source		583
	Distance delivered from Transportation Fuels	km/GJ Primary Source		307
Environmental Metrics				
	GHG			
	Transportation Fuels	g CO2e/MJ		64
	Electricity	g CO2e/MJ		126
	Heat	g CO2e/MJ		76
	Land Use			
	Transportation Fuels	ha/PJ		nil
	Electricity	ha/PJ		nil
	Heat	ha/PJ		nil
	Water Use			
	Transportation Fuels	m3/GJ		0.004
	Electricity	m3/GJ		0.27
	Heat	m3/GJ		0.057
	Air emissions			
	Transportation Fuels	g/MJ		nil
	Electricity	g/MJ		nil
	Heat	g/MJ		nil
	Solids emissions			
	Transportation Fuels	g/MJ		nil
	Electricity	g/MJ		nil
	Heat	g/MJ		nil

Technology Developments – Natural Gas

Incremental Improvement— Shale gas and tight gas technology developments are likely to increase the availability of natural gas in Alberta. Experience in the United States suggests that the cost and efficiency of horizontal drilling will continue to improve. This increases the quantity of economically recoverable reserves and reduces the GHG and land use footprint of natural gas development. Alberta also is likely to benefit from continuing development of gas gathering, separation and transport infrastructure in North America. Additional and improved cost-effective capacity will increase the likelihood that less conventional natural gas reserves in Alberta will be developed in the future.

Breakthrough Technology— While natural gas production technologies are relatively well developed, transport of natural gas over very long distances still is challenging, with LNG the preferred option for long-distance trade. However, LNG economics rely on the economies of massive scale. "Mini-mill" LNG technology could reduce the need for large gas reservoirs, extensive collection facilities and the very large specialty equipment required for current world-scale liquefaction plants. Cost-effective small-scale LNG also would facilitate adoption of LNG as transportation fuel for land vehicles and trains.

The major untapped global natural gas resource is found in gas hydrates, located beneath the ocean floor in certain regions of the world. Japan is one country actively pursuing development of gas hydrates. Alberta will not be able to take advantage of this gas resource directly, but will experience the impact of gas from hydrates on global natural gas markets.

Uranium

The major use of uranium is fuel for nuclear reactors to generate electricity. Today Canada is the second largest uranium producer in the world. High- grade uranium deposits are mined in Northern Saskatchewan. These ores are processed in very large, sophisticated milling and extraction plants in Saskatchewan and Ontario. Of the uranium isotopes, U-238 is most prevalent in nature, but U-235 is most important for nuclear reactors. A portion of Canada's uranium is processed into fuel rods in Ontario for use in Canadian CANDU (heavy water) nuclear reactors in Ontario, Quebec and New Brunswick. CANDU reactors do not require high concentrations of U-235 in the reactor fuel. A portion of Canada's uranium is exported where it is enriched in U-235 and made into fuel rods for light-water reactors that use enriched uranium. No uranium is mined in Alberta today. Exploration activities have identified two areas in Alberta that may have uranium deposits that are viable for development, southern Alberta and northeastern Alberta near the Saskatchewan border (see Figures 5.23 and 5.24). These exploration activities are in the very early stages and it is unlikely that uranium will be mined in the time frame of the Study.

Figure 5.23
Uranium Deposits in Northern Alberta/Saskatchewan

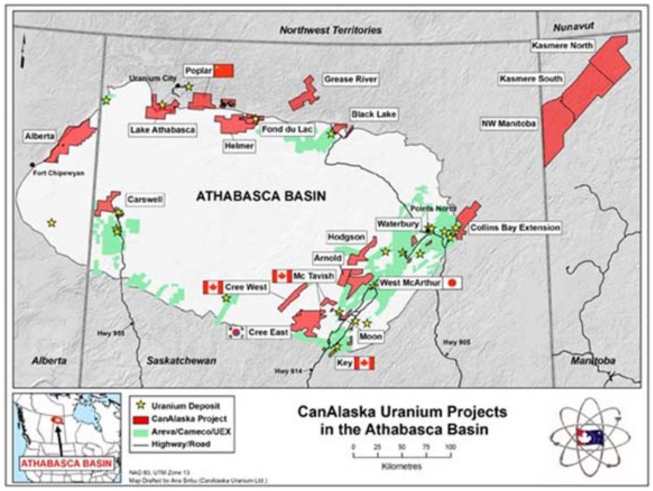


Figure 5.24
Uranium Deposits in Southern Alberta

Nuclear Power from Uranium

The generation of electrical power from uranium requires a number of steps:

- Mining of uranium ore
  - Extraction: Both open pit and underground mining techniques are used. Ore bodies in Northern Saskatchewan have been mined using both methods.

- In situ leaching: In situ leaching (ISL) also is known as solution mining or in situ recovery. Approximately 45% of the world's uranium is mined using ISL. In the United States, it is now considered to be the most cost effective and environmentally acceptable method for uranium mining (World Nuclear Organization). ISL requires much lower capital costs than conventional mining techniques. The deposits in Southern Alberta are being considered for ISL extraction techniques. In ISL, the uranium is recovered by pumping water, a complexing agent and an oxidant into the underground ore body via injection wells. The ore is recovered by leaching. A solution with the ore (the pregnant solution) is returned to the surface and the uranium is recovered using ion exchange. There is less surface disturbance than in conventional mining and there are no tailings or waste rock generated. The ore body must be permeable to liquids and located where the groundwater will not be contaminated.

- Milling— The mixed uranium ore is milled to a uniform particle size. The milled particles are extracted using a strong alkali or strong acid and the uranium is precipitated out of the solution. The process creates a dry powder that is called "yellow-cake" that consists of natural uranium, U_3O_8. The yellowcake typically contains about 80% uranium. In Canada, there are large and technically advanced mills in Northern Saskatchewan at McClean Lake, Rabbit Lake and Key Lake production centers.
- Conversion— In Canada, Canadian and imported mine concentrates are refined to uranium trioxide (UO_3) at the Blind River, Ontario facility. The UO_3 is trucked to the conversion facility in Port Hope, Ontario. Approximately 20 % of the UO_3 from the Port Hope facility is converted to UO_2 for fuel for CANDU heavy-water reactors. The remaining 80% is converted to uranium hexafluoride (UF_6) to produce enriched fuel for light-water reactors.
- Enrichment— The U-235 content of the UF_6 from the conversion plant is enriched via gas diffusion or centrifuges to increase the concentration to 3 - 5%. Gas diffusion requires much higher energy input than gas centrifuges. The enriched uranium hexafluoride is converted into UO_2 powder. There are no enrichment facilities in Canada.
- Fabrication— UO_2 powder, whether from natural uranium or from enrichment, is sintered to create ceramic pellets. The pellets are processed to create a uniform pellet size and then stacked into fuel rods which are grouped to create fuel assemblies. The materials of construction, fuel rod size and bundle layout are dependent on the reactor design. In Canada, the natural uranium is sent to fuel fabricators that produce fuel rods for the CANDU reactors. For most light-water nuclear reactor reactors, enriched uranium is used to fabricate the fuel rods.

- Power Production— The fuel rods are used for approximately 18 months to two years, after which the reactor is shut down and some of the rods are removed and replaced with new fuel rods. Only about 1/3 of the fuel rods will be replaced at the end of a fuel cycle. The CANDU reactors are refueled without shutting down the reactors. The spent fuel rods contain fissile material and continue to generate heat. They are placed in water pools to keep the fuel rods cool and to provide radiation shielding. After the rods are cooled they may be sent for re-processing or to storage.
- Waste Disposal— The waste from the uranium fuel cycle contains different levels of radioactivity and comes from different sources:
    - Low-level waste produced at all stages of the fuel cycle
    - Intermediate-level waste produced during reactor operation and by reprocessing
    - High-level waste, which is waste containing fission products from reprocessing or the used fuel itself

Energy Available from Uranium and Nuclear Power

The available energy for nuclear power in Alberta might be evaluated by looking at uranium reserves in Alberta or by evaluating the production of power by nuclear power plants in Alberta. Because we are at a very early stage of exploration for uranium in Alberta, it is forecast that there will be no production of uranium in Alberta in the 20-year time horizon of the Study. There are no apparent technological barriers to the implementation of nuclear power in Alberta and it is conceivable that one or more nuclear power plants could be built in Alberta in the time horizon of the Study. However, limiting factors to new nuclear power plants include the identification of appropriate sites that have the required stable geological characteristics, adequate water supplies for cooling and supply to the steam generators, and acceptance of nuclear technology by Albertans. (Panel, 2009)

We can look at the issue of available energy by examining the fit of current nuclear technology to the existing Alberta electrical market. Current, world class nuclear reactors (Generation III or Generation IV) are typically built to produce 7 TWh of electricity per year, while Alberta electricity demand is 75 TWh/yr. Nuclear power plant capacities are typically 600 – 1,700 MWe which is comparable to the size of the combined power plants of the major power plant complexes in Alberta such as Keephills, Genessee, Sheerness, and Sundance, but larger than individual power plants that are approximately 300 – 480 MWe. Introducing much larger power plants to an existing grid will increase the need for back-up power reserves on the grid or greater interties to other regional grids. (Panel, 2009)

There are technologies in development that may enable commercial installation of smaller reactors that could be suitable for, say, oil sands applications. However, these reactors are not fully commercialized and therefore are not included in the available energy metric for the Study.

Power output from nuclear power plants is not easily ramped up or down, therefore, nuclear power plants are used more typically as base-load power supplies. Since the plants have high capital costs, but relatively low operating costs they are also tend to run at full capacity.

Technology Developments—Uranium

New technology developments in nuclear power include incremental improvements as well as potential breakthrough technologies.

Incremental Improvement—

Laser Enrichment Technology— Currently practiced enrichment technology is energy intensive. Laser enrichment technology, projected to have higher efficiencies, has been developed and is in the process of being commercialized. Reduction in energy use in the enrichment step would have significant effects on the energy intensity and GHG footprint of a conventional nuclear reactor.

Gen III and Gen IV Light-Water Reactor Technology— Gen III and Gen IV light- water reactor (LWR) technologies are new reactor technologies designed to have the following features as compared to the current LWR technologies. (Goldberg, 2011)

- Higher fuel burn-up rates
- Higher on stream efficiencies
- Lower water use
- Lower capital cost
- Improved safety features

New Generation CANDU— CANDU has developed a new generation reactor, the ACR-1000 with the following features:

- Light water cooling to reduce cost of the heavy water
- Slightly enriched uranium (1 – 2 %) to reduce enrichment costs as compared to conventional LWR enrichment

Breakthrough Technology—

Small Nuclear Reactors— A number of companies have announced the design of small scale nuclear reactors. These reactors provide the following benefits (Babcock and Wilcox), (World Nuclear Association, 2013)

- Scalable and modular with generating capacity in increments ranging from very small , 5- 10 MWe to medium scale, 250 – 400 MWe
- Often modular in design
- Ability to provide power away from large grid systems

Alternate Fuels— CANDU is developing technology to use alternative fuels for nuclear reactors such as recovered uranium from used light-water reactor fuel rods, low enriched uranium and plutonium mixed oxide, thorium and actinides.

Waste Management— While its waste volumes are very small, nuclear power plants produce nearly all of their waste in the form of solids that must be are closely managed. New technologies are needed to overcome current problems associated with long-term storage of spent fuel at nuclear power plant sites, transport of spent fuel and other waste, and secure, long-term storage that minimizes the risk of accidental release of concentrated radioactive materials. Deep geological repositories (DGRs) have been engineered and both Canada's Nuclear Waste Management Organization (NWMO) and Ontario Power Generation (OPG) are seeking potential sites for DGRs.

Pathways for Delivering Commodity Energy from Uranium

Table 5.12 shows how much electric power is obtained from 10,000 GJ/hr contained in processed uranium fuel.

Figure 5.25 shows the pathways for conversion of the uranium resource to electricity. While nuclear reactors could be used to generate only heat - most likely in the form of steam - we have not considered this pathway in the Study. Radioactivity considerations aside, since transport of steam over long distances is impractical, heat users would need to be located close to the nuclear plant.

Table 5.12
Energy Summary – Conversion of Uranium to Electricity

Nuclear Power Pathway	Factors	Power, GJ/hr
Energy in uranium	Ore quality (% uranium in ore)	10,000
Energy for process technology and fuel rod manufacture	Reactor technology, technology for uranium enrichment	(3,600)
Generation efficiency	33% thermal efficiency	(5,000)
Line Losses to City Gate	Depends on distance and voltage	(50)
Electrical Power Delivered		1,400

Figure 5.25
Uranium to Electric Power

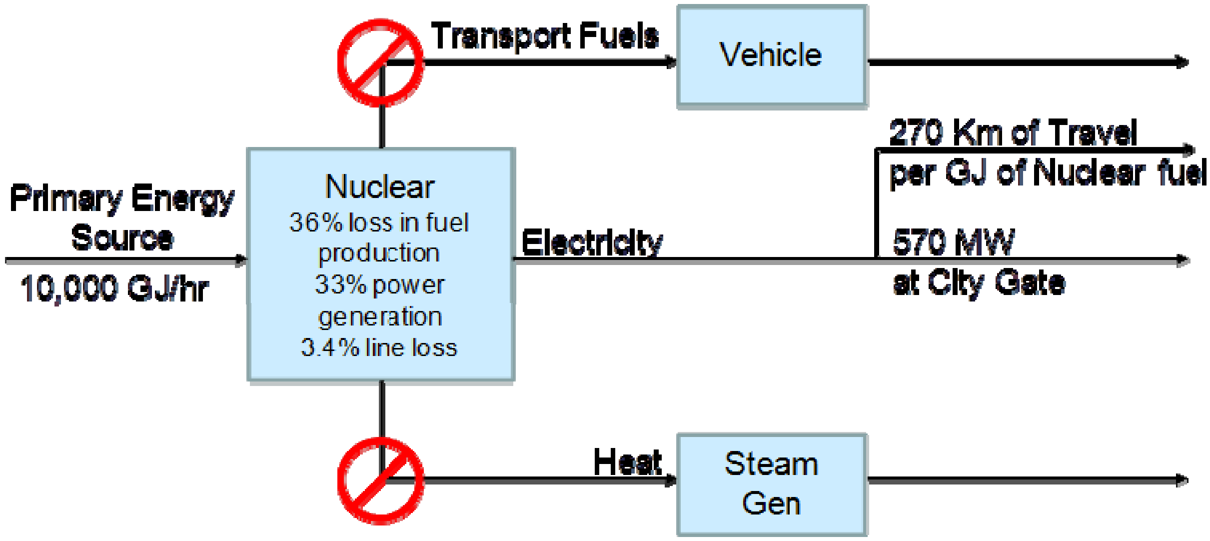


Table 5.13 provides the metrics for uranium.

Table 5.13
Uranium Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Nuclear
Energy Type				
	Type of Source			Stock
	Remaining Established Reserve Potential, Primary Source	PJ		not available
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr	86	
	Electricity	GWh/yr	75,500	
	Heat	PJ/yr	1,260	
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr	468	
	Electricity	PJ/yr	272	
	Heat	PJ/yr	1,260	
Energy Density of Energy Source				
	Primary Source (LHV) - from ore	MJ/kg		3900
Efficiency and Energy Consumption				
	Energy Consumption			
	Electricity	GJ/GJ		2.3
	Net Energy Ratio			
	Electricity	GJ/GJ		0.19
	Electricity Conversion			
	Efficiency of power plant conversion	%		33
	Electricity	kW-hr/GJ Primary Source		57
	Distance Delivered			
	Distance delivered from Electricity	km/GJ Primary Source		268
Environmental Metrics				
	Electricity	g CO2e/MJ		1.8 - 4.2
	Land Use			
	Electricity	ha/PJ		0.9
	Water Use			
	Electricity	m3/GJ		0.52
	Air emissions			
	Electricity	g/MJ		0.00
	Solids emissions			
	Electricity	g/MJ		13.1

Sources: (Heat Values of Various Fuels), (Mielke, 2010), (NETL, 2012) (Warner E. H., 2012)

Hydroelectric Power

There are two energy pathways for electrical power generation from water that are used in Alberta, reservoir power generation and run of river units.

Reservoir or Storage Plants: Alberta has approximately 800 MW of installed capacity of reservoir hydroelectric power plants. There are two relatively large units, Brazeau and Bighorn, and a system of 11 smaller units on the Bow, Spray, and Kananaskis Rivers. These plants have a reservoir to store water which allows the operator to dispatch power as needed. Water turbines linked to power generators are connected to the reservoir via tunnels. In some cases, existing lakes are used as the reservoir and enlarged for the power plant. Multiple reservoirs may feed one generating station. In Alberta, these units typically are run in peaking operation mode from December through February.

Run of River Units: There is approximately 100 MW of installed capacity that uses diversion tunnels to route water through turbines, often at the site of existing irrigation dams and canals. These units do not operate in the winter. They are relatively inexpensive and have fewer environmental impacts than reservoir hydroelectric power plants. Run of river units are smaller in scale than reservoir based power plants, with sizes ranging from 2 – 32 MW..

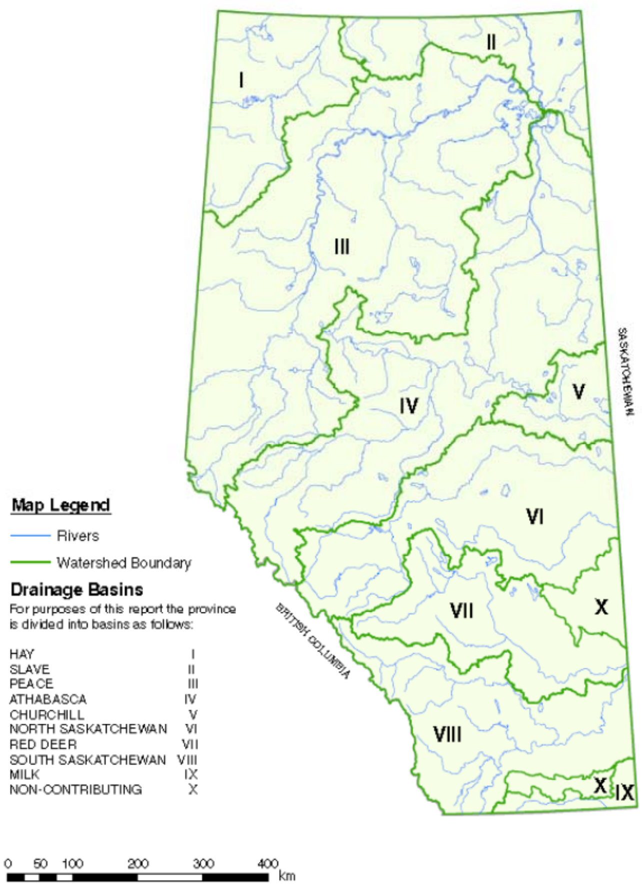
Energy Available and Commodity Production— Hydroelectric Power

The available energy of hydroelectric power in Alberta can be characterized in four ways according to a report published by Hatch Engineering (Hatch Engineering, 2010). The study looks at the flow of water in all parts of Alberta as shown in Figure 5.26. Available energy can be calculated as either:

- *Theoretical maximum hydroelectric energy potential* – It is calculated as the flow of water in rivers in the system multiplied by the height change, derated by a capacity factor of 70%
- *Ultimate developable hydroelectric energy potential* – This is simply one-half of the theoretical maximum. It assumes that 50 percent of the theoretical maximum will be constrained by both competing uses for water such as irrigation, recreation and also limitations imposed by national and provincial park legislation.
- *Developed hydroelectric energy* – Energy that could be produced by hydroelectric power installations that currently are operating in Alberta
- *Remaining developable hydroelectric energy potential at sites that have been identified* – Energy that could be produced in sites that have been identified as potential production sites would be developed, for example, the Dunvegan project on the Peace River
- *Remaining developable hydroelectric energy potential at unidentified sites*: – Calculated as the ultimate developable hydroelectric energy potential, or developed hydroelectric energy less remaining developable hydroelectric energy potential at sites which have been identified

ÉEM Inc used an alternative approach to estimating hydro potential in Canada in a 2006 study. They compiled technical hydropower potential data from various provincial utility and government reports. In most cases, technical potential included only hydropower development at undeveloped but identified sites. In a few instances, technical potential also included redevelopments at existing hydropower sites, expansion projects, and pumped storage alternatives. ÉEM's methodology did not follow the conceptual approaches in the categories listed above. It was restricted by the availability of data. However, the study arrived at a conservative estimate of the rough equivalent of *remaining developable hydroelectric energy potential at sites that have been identified*. The analysis used a 60 per cent capacity factor and arrived at a technical potential of 11,775 MW for Alberta, the fourth highest potential of all 13 Canadian jurisdictions. **(EEM Inc, 2006)** (

Figure 5.26
Alberta Drainage Basins



(Hatch Engineering, 2010)

We have chosen to report the metric of production of electricity if all of the resource is converted to commodity based on the ultimate developable hydroelectric power potential.
Electrical power from a hydroturbine is calculated as follows:

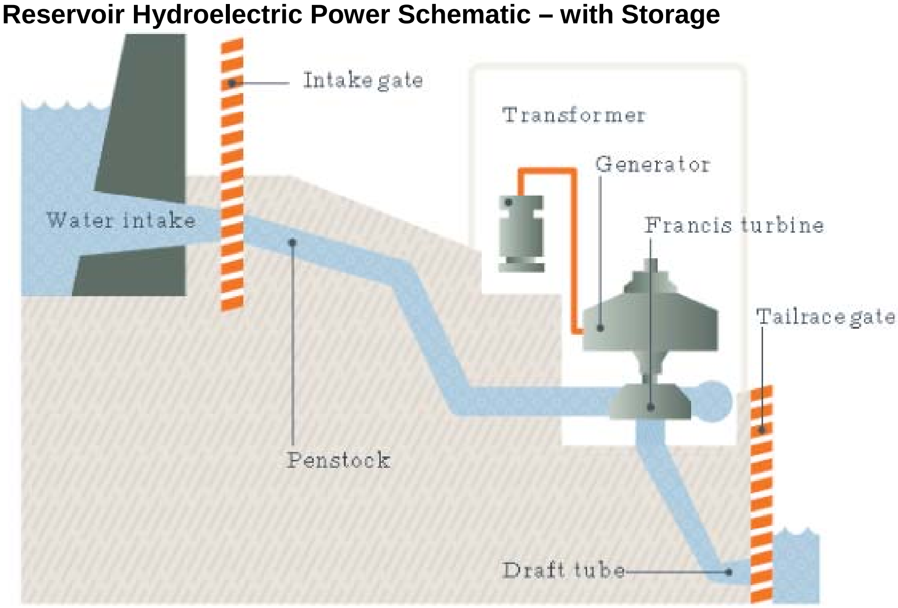
Power (W) = η * ρ * Q * g * h

Where:
η = turbine efficiency = approximately 70% based on reported power production and nameplate capacity in Alberta; this is a relatively high turbine power plant efficiency
ρ = density of water – kg/m3
Q = flow of water – m3/sec
g = acceleration due to gravity – m / sec2
h = height of the water falling – m

The flow of water is available from survey data of annual average stream flow of Alberta rivers. The measurement of height (h) is measured from the elevation change between the head pond or reservoir full supply level and the tail-water level below a hydroelectric power site or plant at average flow.

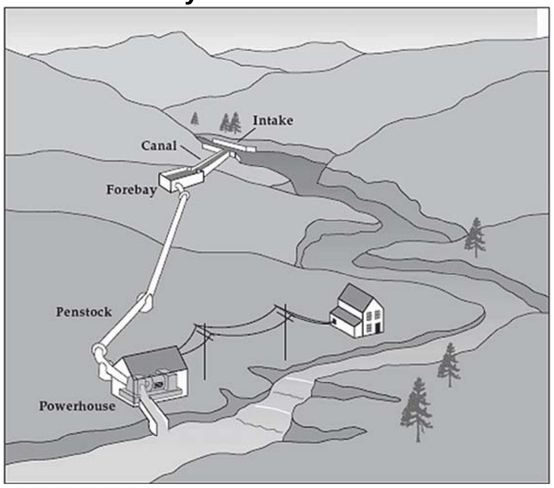
Figure 5.27 and Figure 5.28 show a typical schematic of a reservoir based power plant and a run of river power plant.

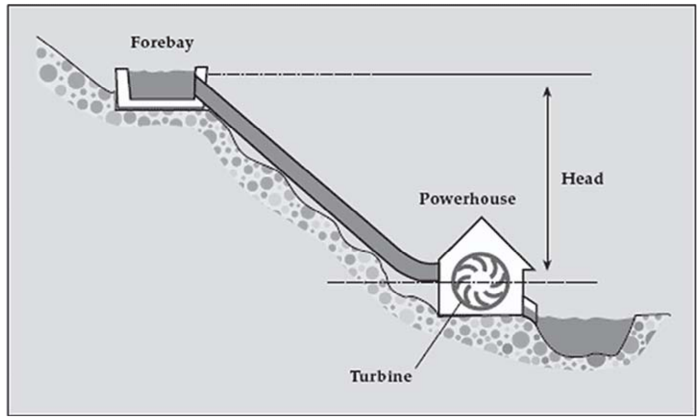
Figure 5.27
Reservoir Hydroelectric Power Schematic – with Storage



(Canadian Hydropower Association, 2008)

Figure 5.28
Run of River Hydroelectric Power Schematic





(US DOI TEEIC, 2013)

Technology Developments— Hydroelectric Power

Incremental improvement— Studies by the US DOE and studies done in Norway estimated a 5 – 10 % improvement (Kumar, 2011) in efficiency can be gained by retrofitting hydroelectric power plants that were built before 1970 through a combination of new equipment, increased capacity, reduced head loss, reduced water losses and improved operations.

Breakthrough Technologies— Many new technologies are aimed at enabling the development of sites where historically the head or the flow of the river was too low for the project to be viable. Some of these new technologies recover directly the kinetic energy of moving water. The results of these developments would be greatly increased availability of hydroelectric power as more potential sites will be viable for development.

- Variable Speed Technology: Technology that allows for greater flexibility of turbine operation, leading to higher efficiencies at variable head and variable flow.
- Matrix Technology: A matrix of small turbines and generators that can be used to adapt to available flow and run under optimal flow conditions. The units can be installed at existing structures, for example irrigation dams, where the water is released at low head.
- Hydrokinetic Technology: Captures energy from moving water such as free-flowing rivers, engineered waterways and tides and currents. EPRI has estimated that the US could double its supply of hydroelectric power by implementing hydrokinetic technology (if fully developed). (EPRI, 2007)

Pathway for Delivering Commodity Energy from Hydropower

Table 5.14 illustrates the energy losses in converting 10,000 GJ/hr of hydropower to electricity.

Table 5.14
Energy Summary – Conversion of Hydropower to Electricity

Hydro Power Pathway	Factors	Power, GJ/hr
Energy in falling water	Volume of flowing water, height of the water falling	10,000
Generation efficiency	Function of generator and turbine design, age and operating characteristics	(3,000)
Line Losses to City Gate	Depends on distance and voltage	(200)
Electrical Power Delivered		6,800

Figure 5.29 shows the energy pathway for hydropower to electricity. Recall that the Study does not consider the use of electricity for heat.

Figure 5.29
Energy Pathway - Hydroelectric Power

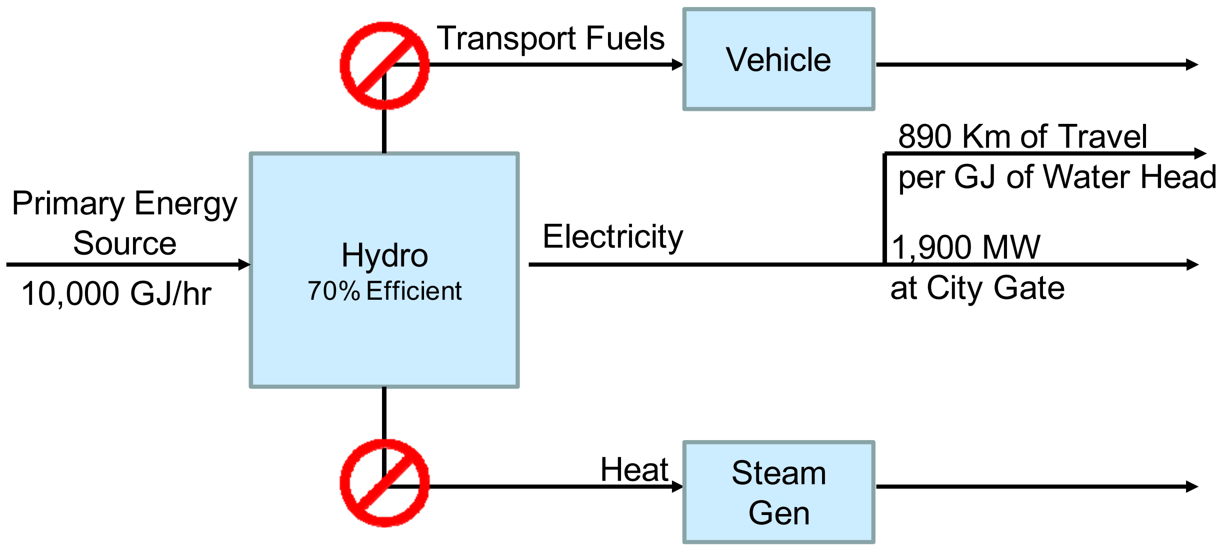


Table 5.15 summarizes metrics for hydroelectric power.

Table 5.15
Hydroelectric Power Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Hydro
Energy Type				
	Type of Source			Flow
Production and Capacity				
	Remaining Established Reserve Potential, Primary Source	PJ		not applicable
	Annual Production of Energy from Primary Source			
	Actual Annual Production, Primary Source	PJ/yr		not applicable
	Available Commodity Production Capacity (Current Installed Capacity)			
	Commodity - Conventional Units			
	Electricity	MW		900
	Commodity - PJ/yr			
	Electricity	PJ/yr		28
	Current actual commodity produced			
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr	86	
	Electricity	GWh/yr	75,500	2,200
	Heat	PJ/yr	1,260	
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr	468	
	Electricity	PJ/yr	272	8
	Heat	PJ/yr	1,260	
	Available Commodity % of Alberta Consumption			
	Electricity	%		3
	Commodity Production if all Alberta Primary Source is Converted to Commodity			
	Commodity - Conventional Units			
	Electricity	GWh/yr		53,050
	Commodity - PJ/yr			
	Electricity	PJ/yr		191
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption			
	Electricity	%		70

Table 5.15 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Hydro
Energy Density of Energy Source				
Efficiency and Energy Consumption				
	Energy Consumption			
	Electricity	GJ/GJ		nil
	Net Energy Ratio			
	Electricity	GJ/GJ		0.70
	Electricity Conversion			
	Efficiency of power plant conversion	%		70
	Electricity	kW-hr/GJ Primary Source		188
	Distance Delivered			
	Distance delivered from Electricity	km/GJ Primary Source		889
Environmental Metrics				
	GHG			
	Electricity	g CO2e/MJ		37
	Land Use			
	Electricity	ha/PJ		5.3
	Water Use			
	Electricity	m3/GJ		6 -70
	Air emissions			
	Electricity	g/MJ		nil
	Solids emissions			
	Electricity	g/MJ		nil

GHG based on NETL reports (NETL, 2012)
Reservoir sizes and energy production information from utility websites (Transalta), (SMRID, 2012) (ATCO, 2013)
Evaporative rates based on NERL and a journal article with detailed evaporation rates from reservoirs worldwide (P. Torcellini, 2003) (Mekonnen M. ,., 2012)

Wind Energy

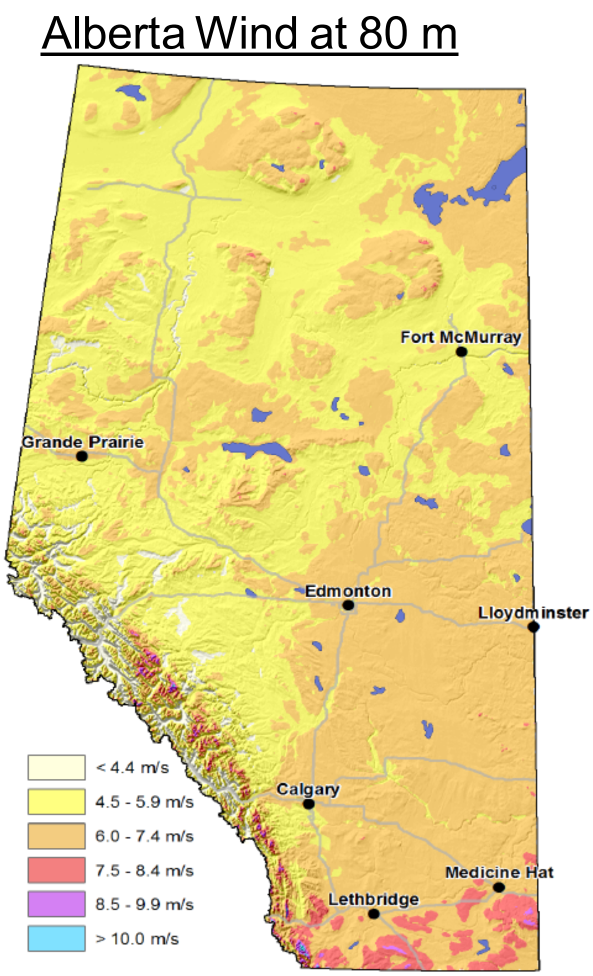
Wind energy may be expressed as the kinetic energy of moving air,

$$\text{Kinetic Energy} = \tfrac{1}{2} * m * v^2 ,$$

where m is the mass of flowing air and v is the wind speed.

There are a number of existing wind farms, primarily in Southern and Western Alberta. The wind resource is best in these parts of Alberta, as evidenced by the wind speed map shown in Figure 5.30.

Figure 5.30
Alberta Wind Map - 80 m Elevation Above Ground Level



(SOLAS, 2013)

Available Energy and Power for Wind

Wind turbines create electrical power from the kinetic energy of the wind by means of momentum transfer from the moving air to the wind turbine rotor. The turbine can capture energy only from air passing through the turbine rotor, so the relevant wind cross-sectional area to consider is always the area swept by the rotor. Power is the rate of doing work, so the power available in air moving through the cross sectional area of the turbine rotor may be expressed as:

$$\text{Power} = \frac{1}{2} * \rho * A * v^3$$

where:

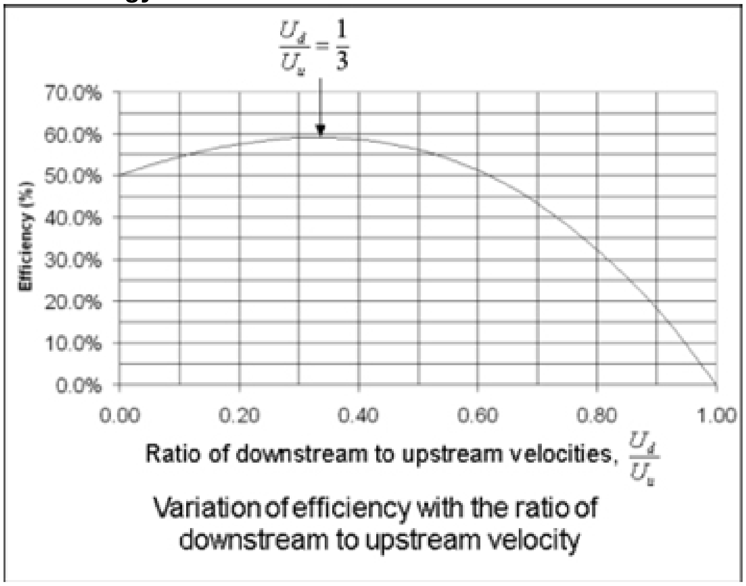
- ρ = Air density in kg/m^3, which depends on elevation, relative humidity, and air temp
- A = Area swept by rotor, and is the area of the circle defined by the turbine diameter, in m^2
- V = Velocity or wind speed in m/sec

However, there are limits on how much energy can be extracted from wind based on the following factors:

- Betz factor: 16/27 – the maximum power that can be extracted from wind
- Turbine power curve – power generation versus wind speed
- Turbine efficiency – how much of the wind energy a turbine can extract
- Wind speed variability
- Conversion losses

The Betz limit describes the physical inability of an airfoil, such as a wind turbine blade, to extract 100% of the kinetic energy in flowing air. (If this were possible, the velocity of the flowing air would be zero downstream of the turbine blade.) The Betz limit expresses how much of the wind energy is available for capture by the turbine. A depiction of the Betz limit over a range of dimensionless downstream/upstream velocities is shown in Figure 5.31.

Figure 5.31
Limits on Energy Extraction from Wind



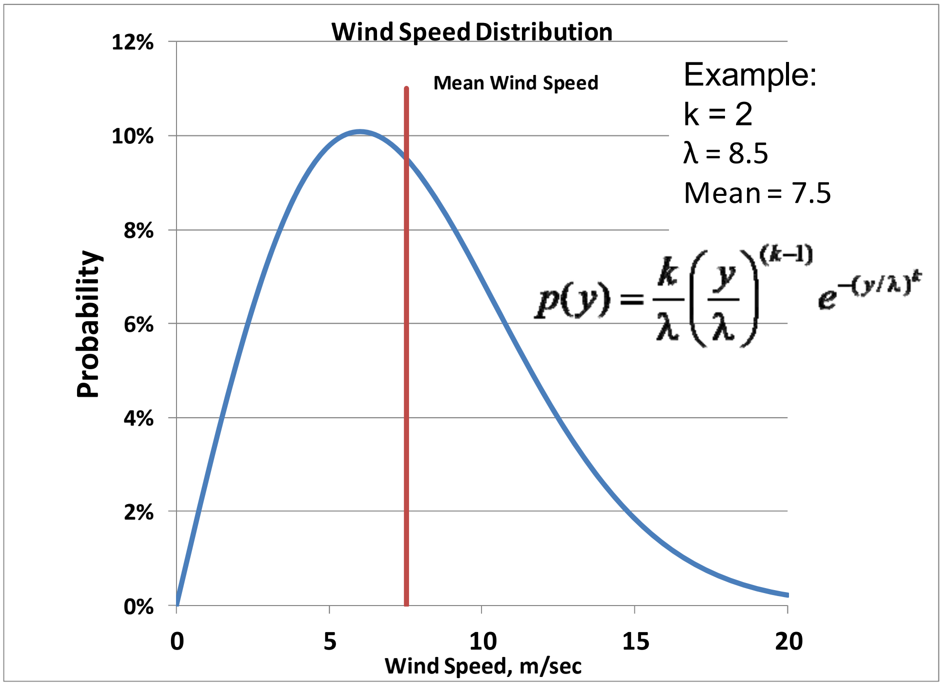
(Wind Power) The Betz limit of 16/27 is reached with U_d/U_u = 1/3

Wind Speed Distribution

Wind power projects are developed by surveying wind speeds as shown in Figure 5.30, selecting appropriate wind turbine technology and designing a wind farm layout that is consistent with the local geography, desired capacity, and economic parameters of the project.

In any given region, wind velocity varies, so data are gathered on the frequency of occurrence for each wind speed to assess the energy available from the wind. When the wind data are analyzed, they often are found to fit a Weibull distribution. (A Weibull distribution allows interpolation between an exponential distribution and a Rayleigh distribution through the adjustable parameters of Scale and Shape.) A model Weibull distribution for wind speed is shown in Figure 5.32. It is convenient to characterize the wind energy available via the mean wind speed (7.5 m/sec in the example). Note that the mean wind speed is not the most probable wind speed (which is lower than the mean). For any mean wind speed, there will be an associated wind speed distribution. To simplify this discussion, we assume the scale and shape parameters do not change for different mean wind speeds.

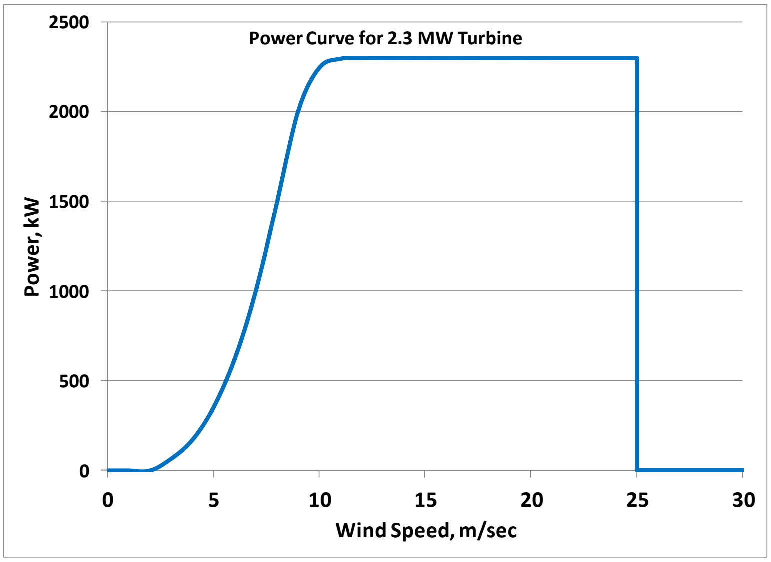
Figure 5.32
Weibull Distribution for Wind Speed



Wind Turbine Power and Mean Power

Wind turbine manufacturers characterize the performance of a wind turbine in terms of the electrical power generated versus a constant or steady-state wind speed. An example of a power curve for a Siemens 2.3 MW turbine with 113 m diameter rotor is shown in Figure 5.33. As can be seen in the figure, as the wind speed varies, so the electrical power generated will vary. This particular turbine generates no electricity at wind speeds below about 2 m/sec, reaches full output of 2.3 MW at wind speeds greater than 10 m/sec, and is shut down for safety reasons at wind speeds greater than 25 m/sec.

Figure 5.33
Power Curve, Siemens 2.3 MW versus Constant Wind Speed



Source: Siemens SWT-2.3-113 Product Brochure
Power curve for: 15 °C air temperature, 101.35 kPa air pressure, 1.225 kg/m^3 air density

We observe that in this example, at wind speeds below 10 m/sec, power output increases rapidly with increasing wind speed. However, at greater wind speeds, the turbine reaches constant full power, up to the turbine cutoff point at 25 m/sec, even though the wind power continues to increase with wind velocity.

It is useful to understand the average power delivered at an average wind speed. We can estimate average or mean power for an average or mean wind speed by accounting for the probability distribution of wind speeds and integrating the turbine power output over all wind speeds:

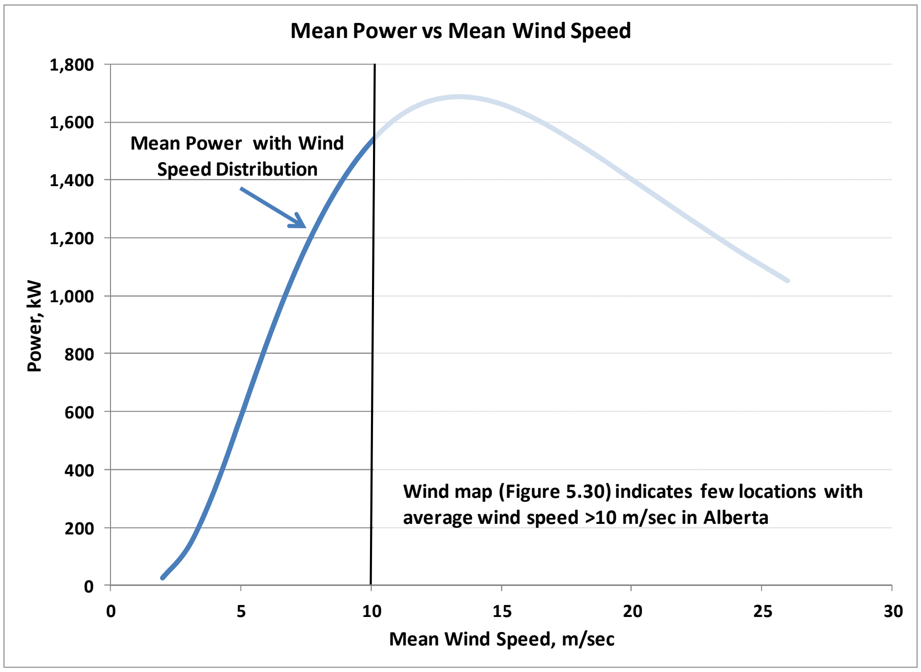
$$P_m(U_m) = \int_0^{\infty} p(u)W(u)du$$

where:

- $P_m(U_m)$ is the mean power delivered at mean wind speed U_m
- $p(u)$ = probability of wind speed u (from the wind speed distribution for mean wind, U_m)
- $W(u)$ = Turbine power output at wind speed u (from the turbine power curve)
- Integrate the product of $p(u) * W(u)$ over all wind speeds to obtain the mean power, P_m

From a series of integrations at different mean wind speeds we can plot mean power versus mean wind speed as shown in Figure 5.34.

Figure 5.34
Mean Power versus. Mean Wind Speed from a Series of Integrations



We observe from the wind speed map in Figure 5.30 that there are very few areas in Alberta where the average wind speed exceeds 10 m/sec.

At wind speeds higher than that at which the turbine reaches full power, the percentage of the wind power captured by the turbine will decrease, since the turbine power output is constant, but the wind power continues to increase with increasing velocity. We may calculate the wind power captured by the turbine as a function of wind speed:

$$\boldsymbol{Fm(Um)} = \int_0^\infty \boldsymbol{p(u)}\bullet[\frac{\boldsymbol{W(u)}}{\boldsymbol{Wind(u)}}]\bullet\boldsymbol{du}$$

where:

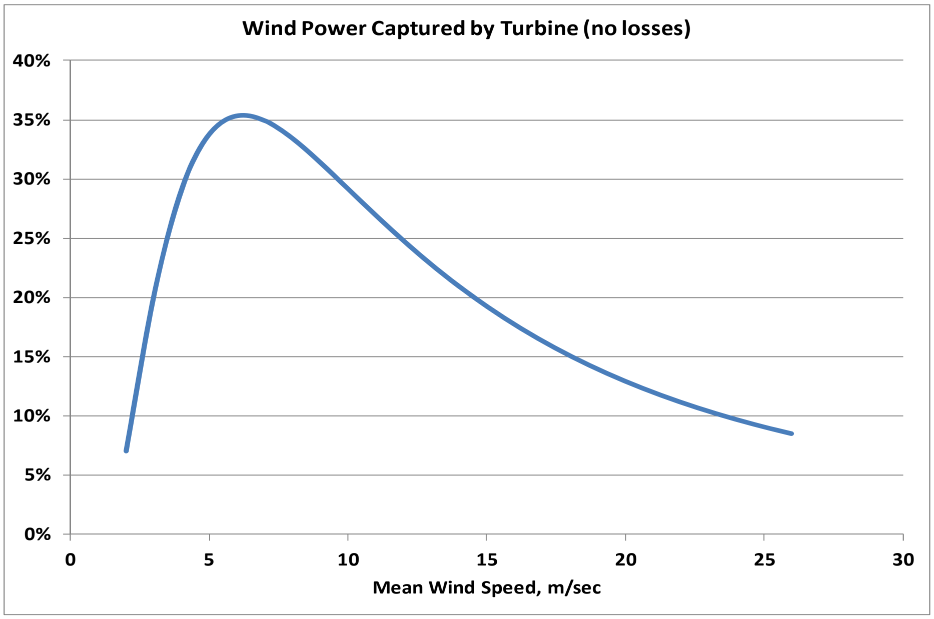
- $F_m(U_m)$ is the fraction of the wind power captured by the turbine at mean wind speed U_m
- p(u) = probability of wind speed u (from the wind speed distribution for mean wind, U_m)

- W(u) = Turbine power output at wind speed u (from the turbine power curve)
- Wind(u) is the wind power at wind speed u (Wind Power = $\frac{1}{2} * \rho * A * u^3$)
- Integrate the product of p(u) * (W(u) / (Wind(u)) over all wind speeds to obtain F_m

Similar to the evaluation of mean power, Figure 5.35 is the result of a series of integrations (at different mean wind speeds) of the ratio of turbine power to wind power. Again, we assume a Weibull distribution with a shape parameter of 2.0 and a scale parameter of 8.5 for all average wind speeds. As an example, we observe that at an average wind speed of 7.5 m/sec, the example turbine could capture about 34% of the power of the wind. At slightly lower average wind speeds, a bit more than 35% of the wind power could be captured by the example turbine.

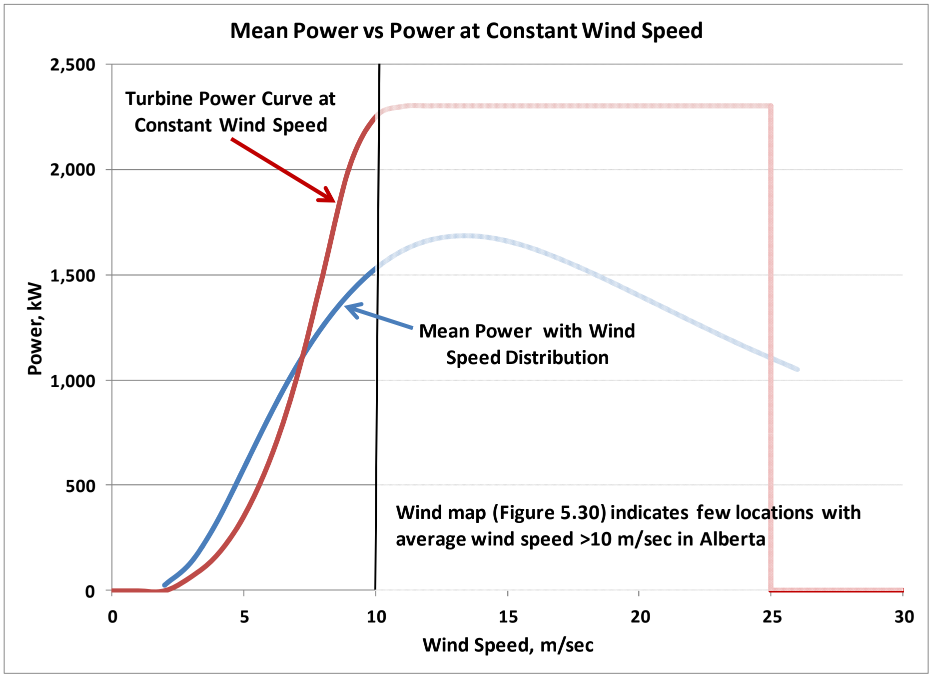
Note that simply taking the ratio of mean turbine power to mean wind power for different mean wind speeds will produce a different result.

Figure 5.35
Wind Power Captured by Turbine



We may compare the mean power curve resulting from the wind speed distribution and the turbine power curve (or steady-state power curve) as shown in Figure 5.36. In the figure, the abscissa (x-axis) refers to the constant or steady-state wind speed for the turbine power curve, or the mean wind speed for the mean power curve. The key to this comparison is that at any average wind speed, the mean power results from integrating over the range of wind speeds covered by the wind speed probability distribution whereas for each point on the steady-state power curve, the power reflects one specific steady-state wind speed. At lower wind speeds, mean power is greater than power at a constant wind speed thanks to the contributions of higher wind speeds in the probability distribution for wind velocity. At higher wind speeds, mean power is less than steady-state turbine power, reflecting contribution of lower wind speeds in the distribution compared to the higher power output at higher steady wind speeds.

Figure 5.36
Mean Power vs. Power at Constant Wind Speed



No mechanical device can operate 100% of the time, and all mechanical devices suffer from various inefficiencies, losses and maintenance outages. In macroeconomic analysis and industrial manufacturing, we normally refer to a utilization rate over an extended period of time as a percentage of stated or nameplate capacity. In the electric power industry the term “capacity factor” is used to denote nameplate capacity utilization.

Wind Turbine Capacity Utilization

For a wind turbine, we calculate the nameplate capacity as the energy that could be generated over the course of a calendar year:

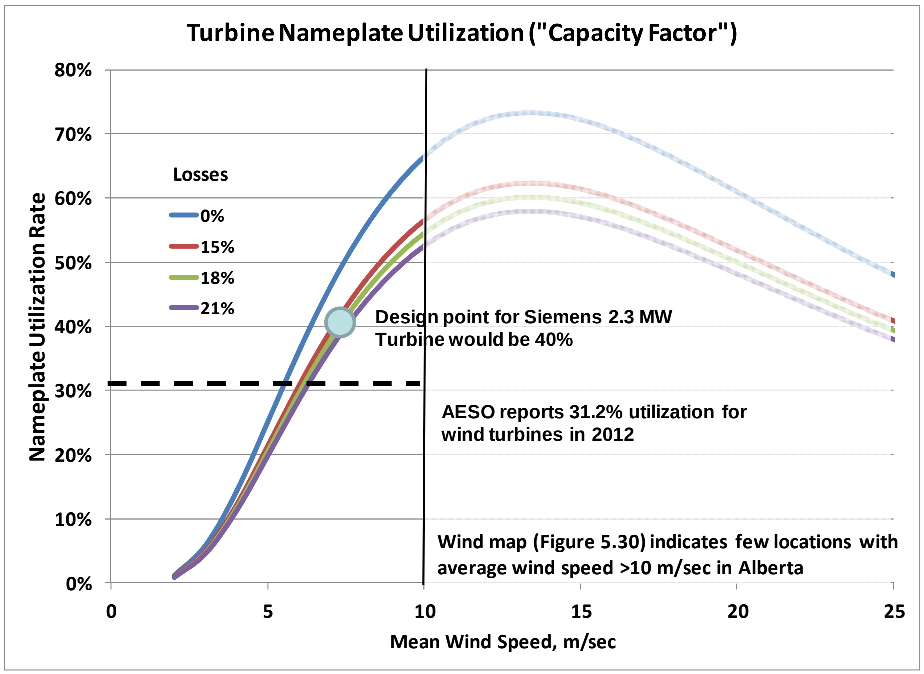
Nameplate capacity = Energy = Turbine Power X 24 hr/day X 365 day/yr
2.3MW Turbine Nameplate capacity = 73 TJ/yr

Then nameplate utilization or capacity factor is the ratio of actual energy generated versus nameplate capacity:

Utilization = Capacity Factor = Annual Energy Generated / Nameplate Capacity

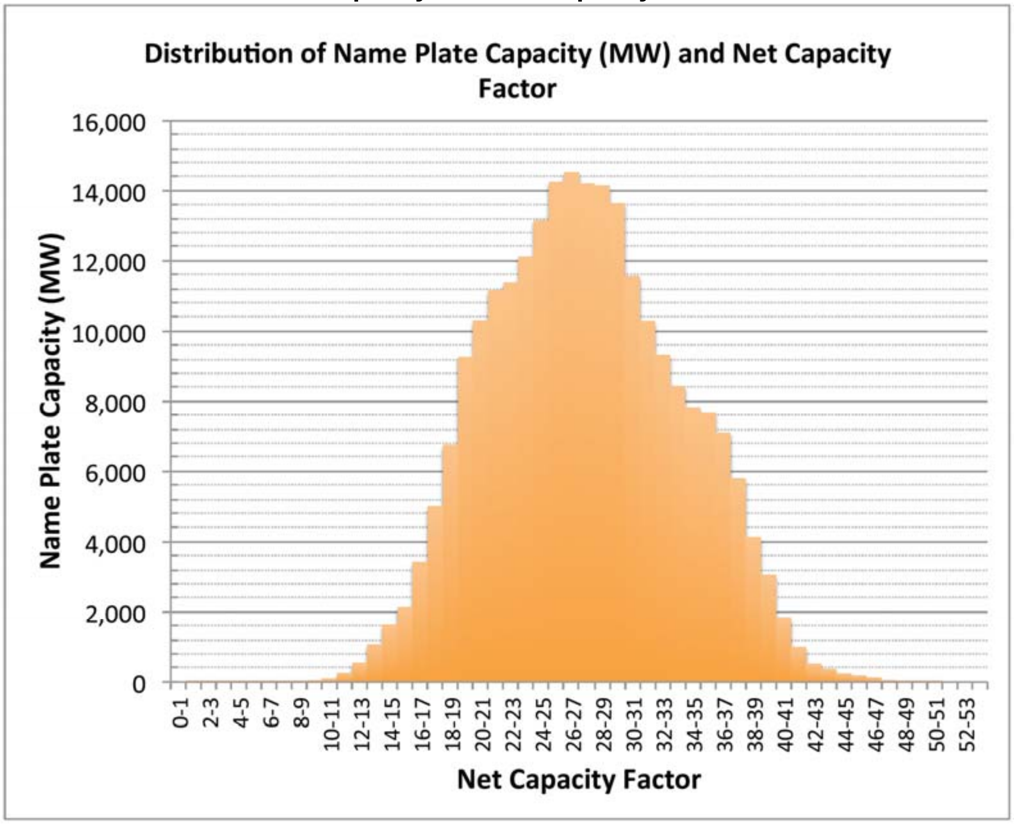
The annual energy generated will depend on wind variability, power dispatch issues, transmission availability, planned and unplanned maintenance and other losses. The wind industry suggests losses of 15-21% are representative (SOLAS, 2013). Using the mean power curve from Figure 5.34, we demonstrate the impact of losses on turbine nameplate utilization in Figure 5.37. For a mean wind speed of 7.5 m/sec, the chart suggests a design utilization rate of about 40% for our example Siemens 2.3 MW turbine. We note that in 2012 AESO reported a combined utilization rate just over 30% for all wind turbines in Alberta (further discussion below). Presumably turbines currently installed in Alberta vary in design and performance from our example turbine.

Figure 5.37
Turbine Utilization Rate



Using wind map studies and economic evaluation, CanWEA developed detailed analysis of potential wind energy projects in Alberta. Their studies resulted in a distribution of wind power capacity versus forecast capacity utilization, as shown in Figure 5.38 (SOLAS, 2013). They concluded that the most attractive future wind projects in Alberta are those with a forecast Net Capacity Factor greater than 38%. These projects represent about 5,000 MW of wind power nameplate capacity.

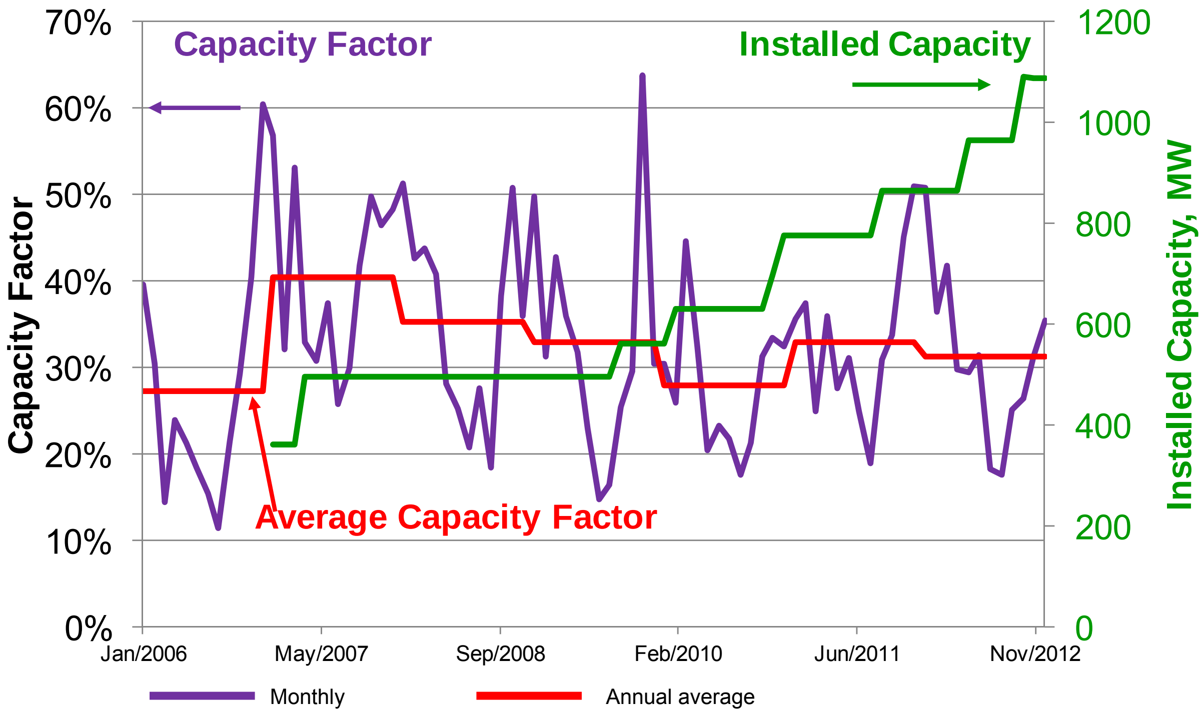
Figure 5.38
Distribution of Name Plate Capacity and Net Capacity Factor



(SOLAS, 2013)

Figure 5.39 shows data from AESO on the short-term (monthly average) and annual average utilization rates (capacity factor) as wind power capacity has grown in Alberta. Recently, utilization rates have been a bit more than 30% of installed nameplate capacity.

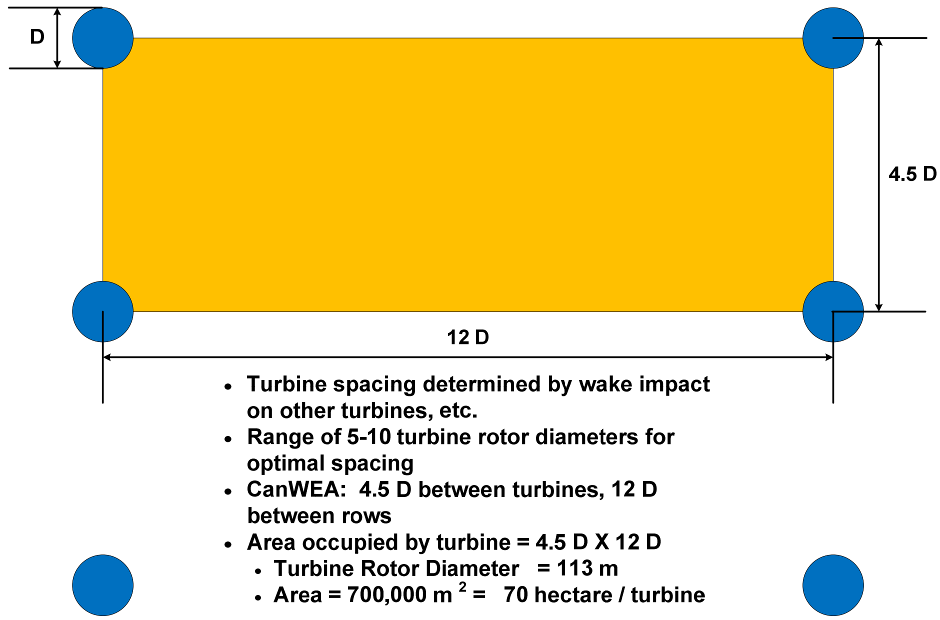
Figure 5.39
Historical Alberta Wind Capacity Factor from AESO



Estimate of Number of Turbines

In order to calculate the potential available energy from wind power in Alberta, we estimated turbine spacing for wind farms and then looked at the total area in Alberta where wind turbines possibly could be placed. To account for wake turbulence and the like, the Canadian Wind Energy Association (CanWEA) suggests that turbines might be spaced in a grid of roughly 4.5 X 12 wind rotor diameters (113 m rotor diameter for the Siemens 2.3 MW turbine) (SOLAS, 2013) Such a grid is shown in Figure 5.40. For a 113 m rotor diameter, each turbine requires about 70 hectares of land (although the actual land disturbed for the turbine footprint itself would be much smaller, and of course, the land near the turbines can be used for other purposes).

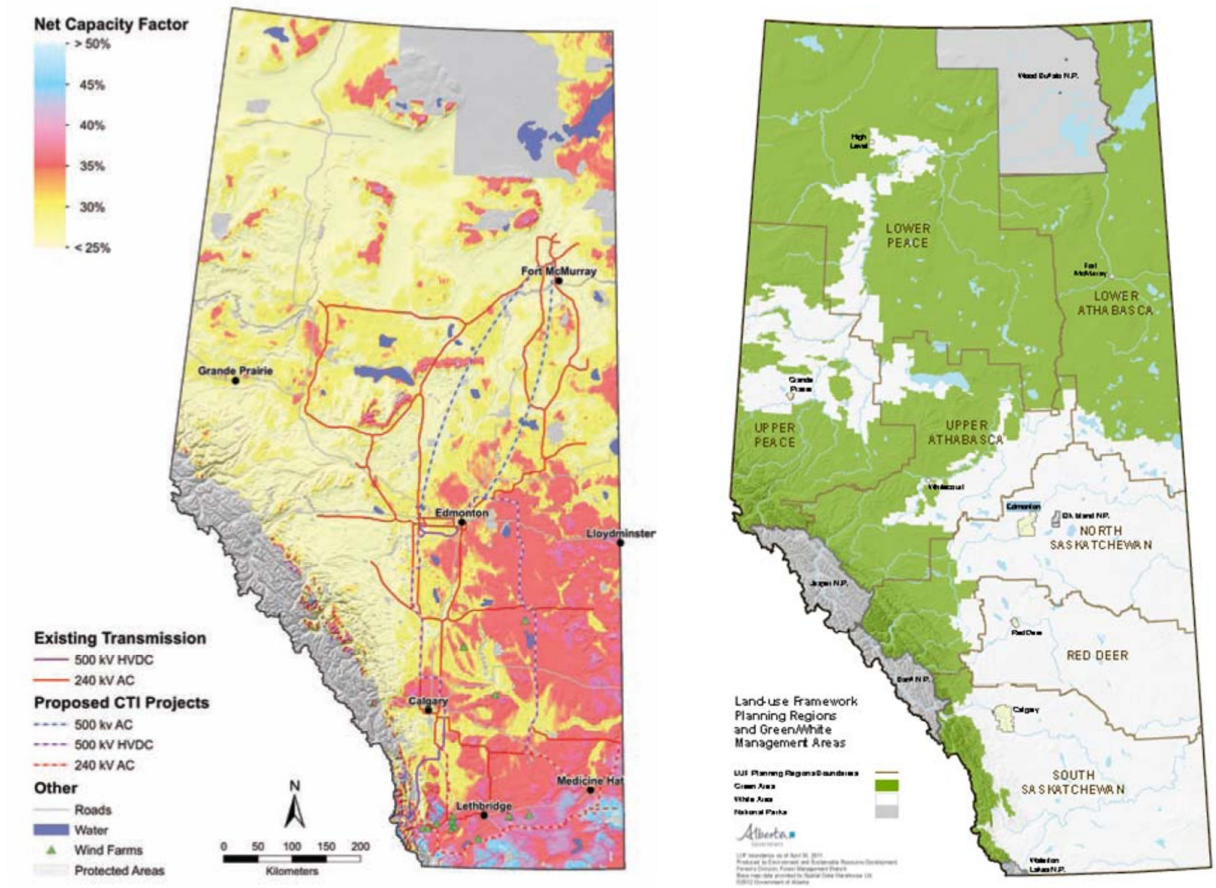
Figure 5.40
Turbine Spacing



The Province of Alberta occupies about 66 MM hectares, with a total land area of about 64 MM hectares. The total agricultural area in the “white area” is about 21 MM hectares including 11 MM hectares of cultivated land and 9 MM hectares of pasture land. (AESRD, 2012) If we assume that wind turbines could be located on the cultivated land plus pasture, then 20 MM hectares of land might be available in Alberta, just over 30% Alberta’s total land mass. In their recent report (CanWEA, 2013), CanWEA suggest that 35% of Alberta’s land is suitable for wind power installations.

The CanWEA wind map is shown in Figure 5.41, along with a map of Alberta’s green and white areas. We note the rough correspondence of the more desirable wind development areas and the white area, but development of wind power in the green area also could be considered.

Figure 5.41
Comparison of Suitable Wind Power Locations with Land Use Framework Areas



Combining the area required for turbine spacing (70 hectares/turbine) with the available land for turbines gives a maximum number of potential turbine installations:

Turbines = 20 MM hectares / 70 hectares / turbine = 285,000 turbines.

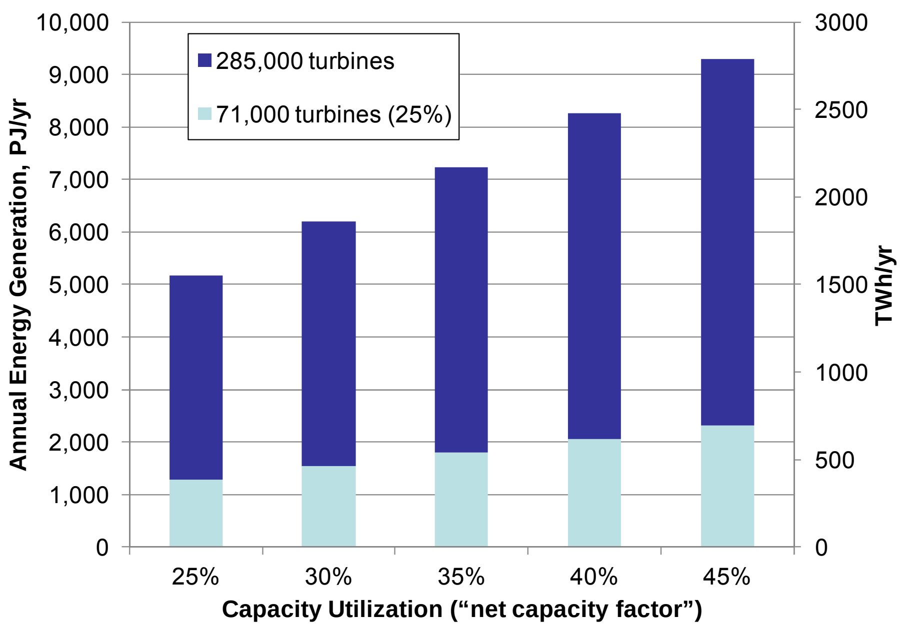
It is unlikely that every single location would be suitable for turbine installation. CanWEA suggests that at most, perhaps 25% of the sites could be utilized. This would result in a maximum of 71,000 potential turbine installations in Alberta. Of course, we have not applied economics, environmental, grid management considerations, back-up power generation requirements or any other factors that might limit the number of wind turbines that ultimately could be installed in Alberta.

Energy Available from Wind Power in Alberta

If each turbine has a nameplate generating capacity of 2.3 MW, then 285,000 turbines represent 660 GW of electrical capacity. If only about 25% of the maximum number of turbines is considered, then the maximum wind power capacity is about 150 GW. Relative to Alberta's total installed electrical generating capacity of about 14 GW, this is a very large number.

Beyond the number of turbines and the nameplate capacity of each, the amount of electrical energy available will depend on what net capacity utilization is realized. Some of the factors influencing the actual electrical energy generated include wind speed variation, energy consumed in maintaining back-up power generation capability to account for intermittent and variable winds (for power grid stability management), parasitic energy consumption for wind turbine lube oil systems, energy for rotor rotation to prevent potential blade warping or other mechanical damage and the like. Ultimately, the amount of wind power that Alberta will be willing to install will be determined by success in managing the stability of the power grid. Figure 5.42 demonstrates the variation in annual electricity generation as a function of the number of turbines and the capacity utilization rate.

Figure 5.42
Potential Energy for Alberta from 2.3 MW Turbines at Different Utilization Rates



Energy Pathway for Wind

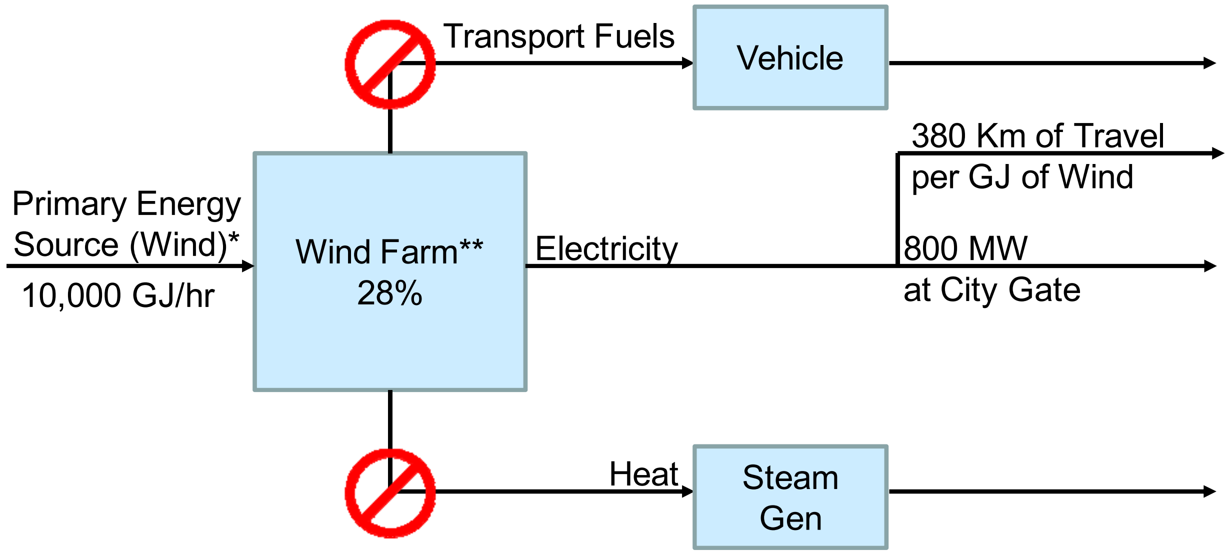
The conversion of wind as a primary energy source to commodity electricity occurs via turbines located in wind farms. Our benchmark primary energy quantum of 10,000 GJ/hr represents the energy of the wind flowing through the swept area of about 550 turbines at an average speed of 7.5 m/sec. As in our previous analysis, the turbines can capture about 34% of the wind energy, and assuming other losses of 18%, the wind farm is about 28% efficient. Table 5.16 summarizes the conversion assumptions.

Table 5.16
Energy Summary – Conversion of Wind to Electricity

Wind Pathway to Electricity	Factors	Power, GJ/hr
Energy in Wind	Swept area of rotor, wind speed variability, air density	10,000
Maximum Energy Available for Capture	Betz Factor limit	(4,100)
Turbine Power Curve and Wind Speed Distribution	Design outcome, function of wind speed, geography, elevation, time of day (34% of wind power at 7.5 m/sec mean wind speed)	(2,500)
Losses (15-21%)	Mechanical, parasitic energy consumption, planned/unplanned outages, dispatch, etc.	(500)
Overall electric power generation		2,900
Line Losses to City Gate	Depends on distance and voltage	(100)
Delivered Power		2,800

Figure 5.43 shows the energy pathway for wind.

Figure 5.43
Energy Pathway – Wind



* Swept area of about 550 turbines
** Assume 7.5 m/s mean wind speed, 34% wind energy capture,18% losses (including line losses)

A summary of metrics for wind energy is shown in Table 5.17.

Table 5.17
Wind Metrics

Metric Type	Metric	Primary Sourc	Alberta Total Demand	Wind
Energy Type				
	Type of Source			Flow
Production and Capacity				
	Annual Production of Energy from Primary Source			
	Available Commodity Production Capacity (Current Installed Capacity)			
	Commodity - Conventional Units			
	Electricity	MW		1,100
	Commodity - PJ/yr			
	Electricity	PJ/yr		35
	Current actual commodity produced			
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr	86	
	Electricity	GWh/yr	75,500	3,000
	Heat	PJ/yr	1,260	
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr	468	
	Electricity	PJ/yr	272	11
	Heat	PJ/yr	1,260	
	Availalble Commodity % of Alberta Consumption			
	Electricity	%		4
	Commodity Production if all Alberta Primary Source is Converted to Commodity			
	Commodity - Conventional Units			
	Electricity	GWh/yr		500,000
	Commodity - PJ/yr			
	Electricity	PJ/yr		1,800
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption			
	Electricity	%		700

Table 5.17 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Wind
Energy Density of Energy Source				
Efficiency and Energy Consumption				
	Net Energy Ratio			
	Electricity	GJ/GJ		0.28
	Electricity Conversion			
	Efficiency of power plant conversion	%		34
	Electricity	kW-hr/GJ Primary Source		80
	Distance Delivered			
	Distance delivered from Electricity	km/GJ Primary Source		380
Environmental Metrics				
	GHG			
	Electricity	g CO2e/MJ		0.07
	Land Use			
	Electricity	ha/PJ		0.00012
	Water Use			
	Electricity	m3/GJ		0.09

Technology developments—Wind

In the time horizon of the Study, improvements in wind power technology are most likely to be incremental, with some opportunity for breakthrough technology.

Incremental Improvement— Wind turbines continue to improve, with larger rotors enabling larger generators and higher hub heights allowing access to more favorable wind. Stronger materials of construction also aid the development of higher-capacity turbines. However there are trade-offs, as larger turbines require additional spacing for a given wind farm area. Current turbines already are quite large and mechanical challenges (large nacelles mounted high in the air, very long, flexible rotors, bearing strength, lubrication, etc,) will increase with larger and larger turbines. Other technology improvements may include reduced energy losses and improved wind forecasting, for siting new wind installations and for managing the delivery of wind power to the electrical grid. Improving electrical grid technology and management also should aid the development of wind power.

Breakthrough Technology— Since wind energy is variable, and since the best winds for generating power often correspond to periods of low electricity demand, the most important breakthrough technology for wind would be efficient and economical large-scale electrical energy storage. Effective storage technology would increase the annual energy generated by wind power installations and would simplify management of intermittency, variability and dispatchability for the electrical grid as wind becomes an increasing contributor to total electrical power generation.

Solar Energy

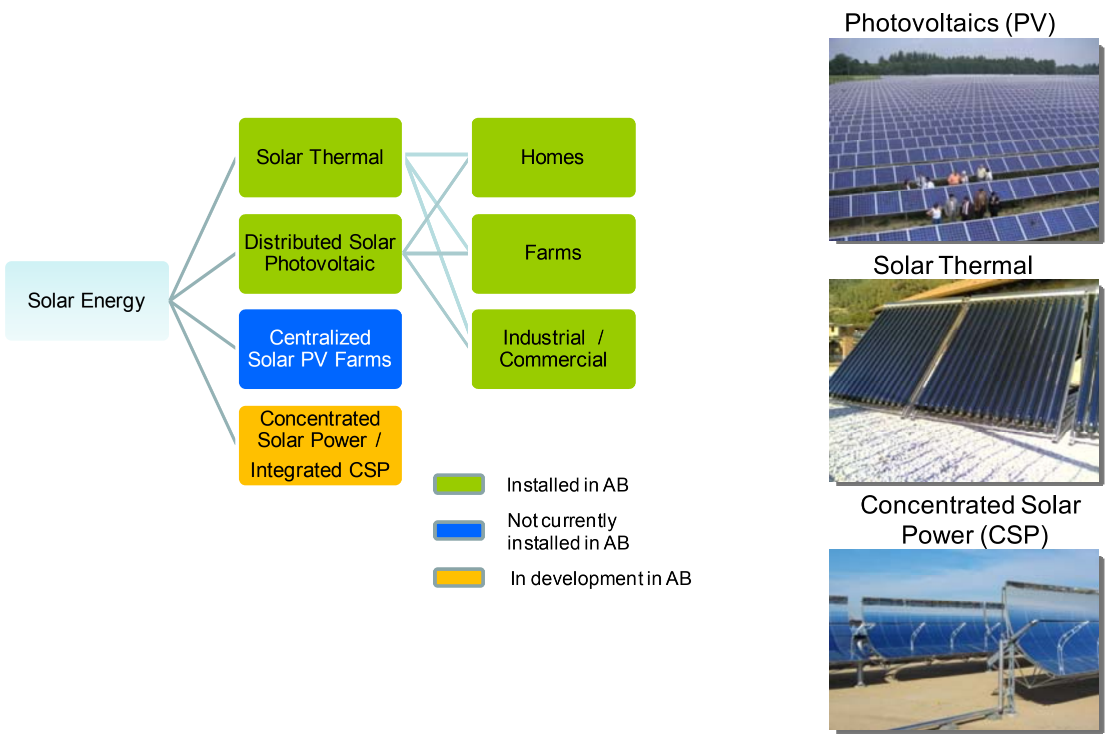
We considered three pathways for the generation of electricity from solar power:

- Photovoltaic distributed generation to electricity
- Photovoltaic utility-scale power plants to electricity
- Thermal solar energy to heat

Stand-alone concentrated solar photovoltaic projects require very high levels of solar intensity that do not occur in Alberta, therefore stand-alone CSP was not included in our pathway analysis. There is a project currently being developed in Medicine Hat to incorporate concentrated solar power integrated with natural gas generation to electricity. The required solar intensity for this project is not found in Alberta outside of the Medicine Hat area, therefore this pathway is not included in the metrics.

In Alberta, there is currently a small amount of distributed generation and no utility-scale power plants. There are solar thermal panels installed in residential and commercial applications. Alberta solar development is summarized in Figure 5.44.

Figure 5.44
Solar Energy in Alberta



Solar Photovoltaic Systems – Distributed and Utility-Scale

Silicon photovoltaic (PV) cells are made of a semiconductor material such as monocrystalline silicon and polycrystalline silicon. Thin film PV technology uses thin films of materials such as amorphous silicon, cadmium telluride, and copper indium gallium selenide/sulfide (CIGS).

The photovoltaic cells are grouped into modules. The modules then are assembled into systems which include an inverter, racking devices, tracking units, cables and wiring, storage devices (if not grid connected), and wiring. These components are referred to as the balance of system (BOS) components. BOS components also can include labor and other non-equipment costs.

A typical solar photovoltaic module has an output of 100 – 250 W. The modules are approximately 0.6 – 1.2 m in size and weigh approximately 10 – 25 kg/panel. Note that Canadian roof design guidelines require a 5 lb/ft^2 (24 kg/m^2) roof load which can limit the number of panels that can be installed on a roof.

Calculation of Solar Photovoltaic Power Output

Power output of a solar photovoltaic cell can be calculated as:

Power output = insolation X conversion efficiency X performance ratio
X module life time X area

Each contribution to power output is discussed below.

Insolation

Insolation measures the total amount of energy delivered to the surface over time. Data are gathered by solar reporting stations and can be found on the NRCAN websites. The mean daily Alberta insolation rate is 4.2 – 5 kWh/m^2/day (assuming south facing, tilt = latitude configuration) which is equivalent to a yearly insolation rate 1530 – 1830 kWh/m^2/year.

Conversion Efficiency

Typical cell conversion efficiencies are as shown in Table 5.18

Table 5.18
Solar PV Cell Conversion Efficiencies

Cell Type	Typical Efficiency
Amorphous Si	6.3
CdTe	10.9
CIGS	11.5
Mono-crystalline	14.0
Multi-crystalline	13.2

Cell efficiencies degrade over time. Estimates of cell efficiency degradation range from 1.0-0.5% per year over the lifetime of the module, as compared to the initial cell efficiency. Silicon solar cell efficiencies are highly dependent on temperature. Manufacturers report solar cell efficiencies at a standard temperature of 25 °C. Cell efficiencies decline as temperature rises so that winter operating regimes will have higher efficiencies than summer operating regimes. A typical silicon solar cell will have the following efficiency temperature relationship:

$\text{Efficiency}_T = \text{Efficiency}_{STC}$ X (1 - 0.004 X (T – 25 °C)) (Nishioka, 2003), where

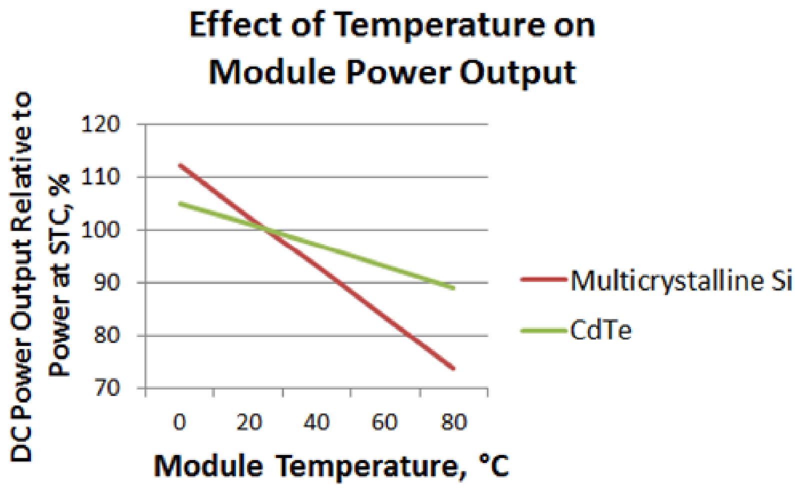
$\text{Efficiency}_{T\,=}$ Efficiency at the operating temperature,

Efficiency_{STC} = Efficiency at the standard operating condition of 25°C,

T = cell operating temperature

The effect of temperature is also dependent on the solar cell material. Figure 5.45 shows the temperature relationship for multicrystalline Si cells and for CdTe cells.

Figure 5.45
Effect of Temperature on Module Power Output



Based on data from First Solar (N. Strevel, 2012)

Performance Ratio

Performance ratio takes into account a number of components in the performance of the system:

- **Tracking** - The efficiency of the system improves if tracking is used to maximize solar irradiance on the modules. A derate factor of 1.0 assumes that the modules are always positioned in the optimal orientation to the sun. The increase in system output is dependent on the latitude of the system, irradiance and on the type of tracking system. Reported mean daily global insolation values for Alberta increase by approximately 50% when comparing systems with a fixed south facing, tilt = latitude system to a system with two – axis tracking (NRCAN, 2012).
- **Inverter efficiency** – the inverter converts the DC power generated by the solar cell to AC power
- **Mismatched modules** – Factory produced modules have slightly different current-voltage characteristics. Inefficiencies occur when mismatched modules are connected.
- **Soiling** – Dust and dirt will collect on the module surface and decrease efficiency. In northern regions, snow also may block the ability of the cell to generate power. The modules may need to be installed at an angle sufficient that the snow will slide off or they must be otherwise maintained to keep them snow free. Regions with high levels of dust or little rain will incur more soiling.

- **Diodes and connections, AC wiring, DC wiring –** resistive losses associated with connections and wiring
- **System availability –** estimation of the time that the unit will not be available due to maintenance and downtime for inverter and utility outages.
- **Age –**over time, the efficiency of the solar cell decreases due to weathering. The change is typically 0.5 - 1% per year.

Table 5.19 shows the "derate factors" (performance ratios) built into the PVWATTS program created by the US NREL. This program is widely used to determine grid connected solar PV system performance. Typical performance ratios reported in the literature range from 0.75 - 0.8.

Table 5.19.
Performance Ratios for Solar PV

Component	PVWatts	Range
PV module nameplate DC rating	0.95	0.80 - 1.05
Inverter and transformer	0.92	0.88 - 0.98
Mismatch	0.98	0.97 - 0.995
Diodes and connections	0.995	0.99 - 0.997
DC wiring	0.98	0.97 - 0.99
AC wiring	0.99	0.98 - 0.993
Soiling	0.95	0.30 - 0.995
System Availability	0.98	0.00 - 0.995
Shading	1.0	0.00 - 1.00
Sun-tracking	1.0	0.95 - 1.00
Age	1.0	0.70 - 1.00
Overall factor	0.77	

(NREL, PVWatts, 2013)

Module lifetime

Module lifetimes have improved with technology developments. Typical module lifetimes are currently estimated to be 30 years.

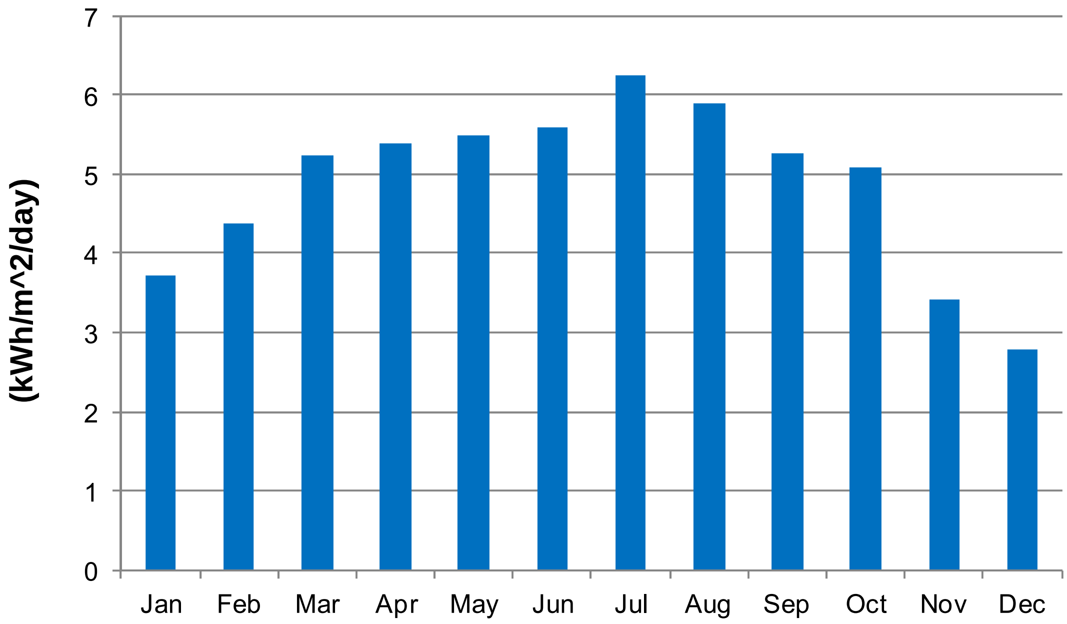
Area

The area is the area of the module exposed to solar insolation.

Solar Insolation Variability

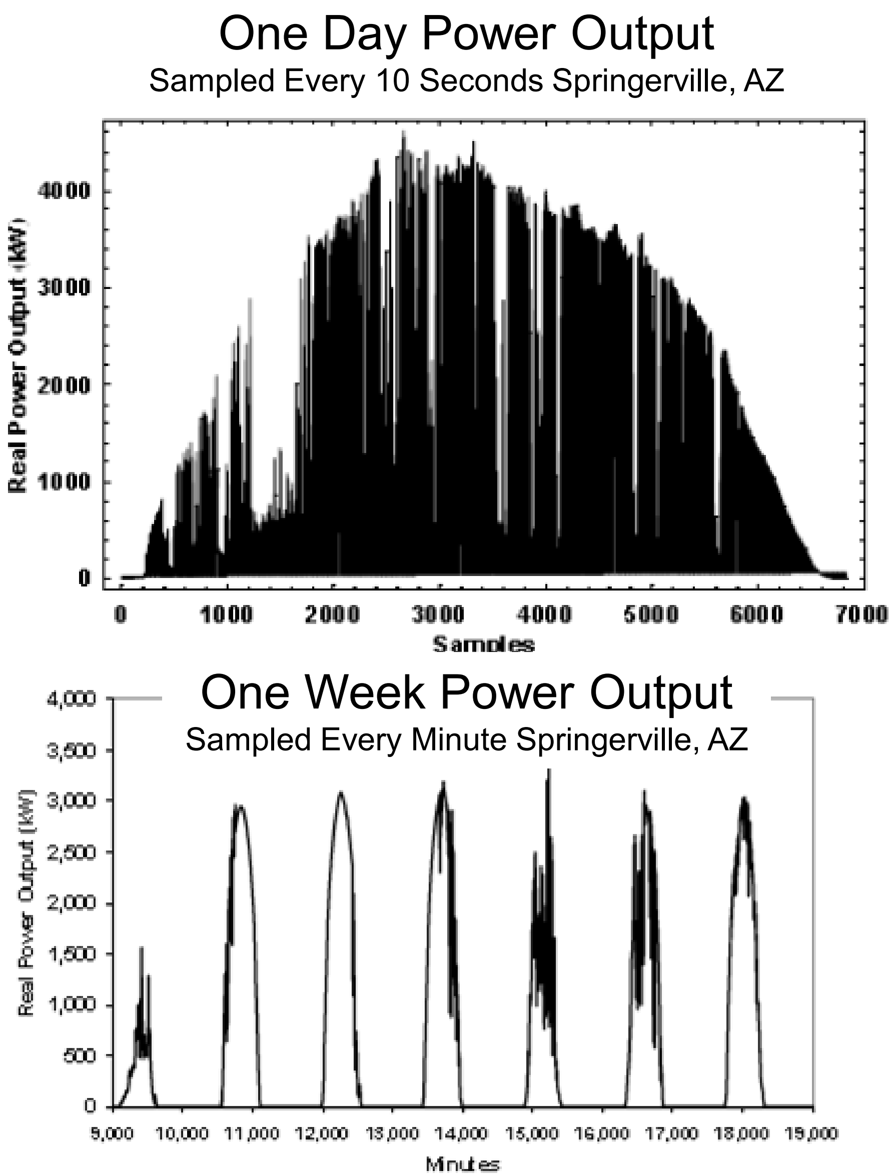
Solar insolation variability has two aspects, predictable variability on a monthly and diurnal cycle and instantaneous variability due to cloud cover. Figure 5.46 shows the monthly changes in solar insolation in Calgary and Figure 5.47 shows the one day and one week power output from a solar installation in Springerville, Arizona.

Figure 5.46
Monthly Solar Insolation Calgary, AB



(NREL, PVWatts, 2013)

Figure 5.47
Solar Variability



(Apt)

Available Energy and Commodity Production: Solar PV Distributed and Utility-Scale

In Figure 5.48, we observe that despite its northern latitude, the dry climate of Alberta provides a robust solar resource that is comparable to the solar resource found in Southern Europe, but not quite as good as the Southwestern US.

Figure 5.48
Alberta Solar Insolation as Compared to other Regions

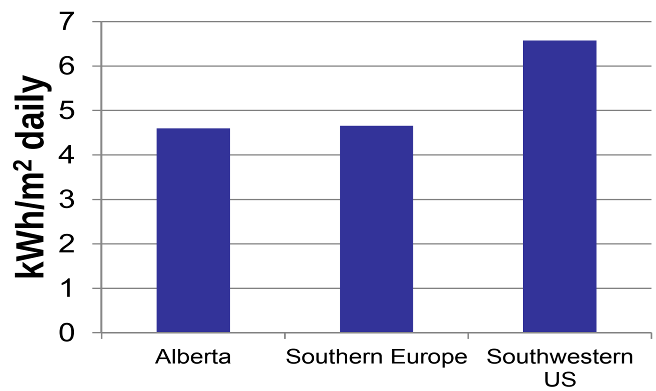
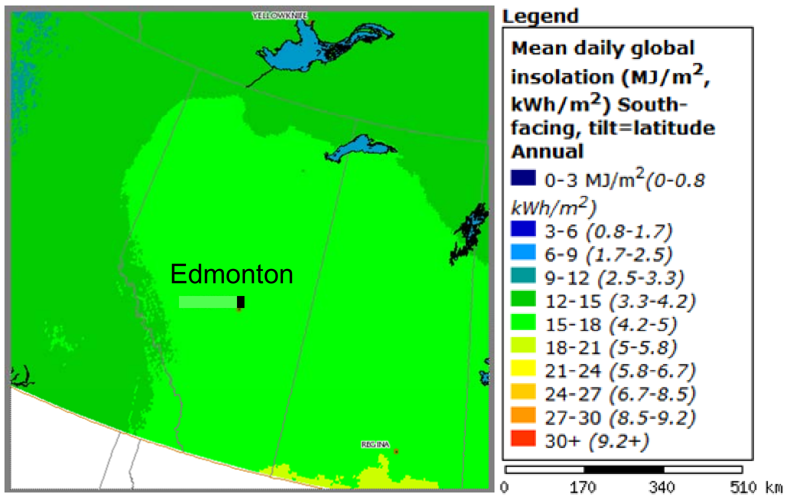


Figure 5.49 from NRCAN shows solar insolation for Alberta. Solar insolation available to the solar panel is affected by the orientation of the modules and the ability of the modules to track the sun. Changing from a horizontal orientation to a tilted orientation has a significant effect on measured insolation.

Figure 5.49
Alberta Solar Insolation

Solar – Insolation – MJ/m^2



(NRCAN)

Currently, solar photovoltaic installations in Alberta are small distributed power systems. The units may be connected to the grid and the owners can sell energy back to the grid. The estimated installed capacity is 3.2 MW (Kelly, 2013). There are no utility-scale installations. The actual energy generated with the current installed capacity is not reported.

We assessed the commodity production for distributed photovoltaic power in Alberta by segmenting the possible applications for solar PV into the following segments: industrial locations, farms, urban rooftops. Table 5.20 shows the calculation of potential solar PV in Alberta for distributed generation. Note that this calculation assumes that all appropriate connections will install solar PV systems. A solar insolation of 1,200 kWh/kW was assumed for the calculation.

Table 5.20
Estimate of Solar PV Distributed Power Generation

	Number of Connections	% Available	Typical Installation Size (kW)	Power Output (PJ/year)
Residential	1.2 million	50 % south facing 30% shaded	2 – 5	7
Farms	107,000	100%	10	5
Commercial	165,731	50% south facing 30% shaded	20	5
Industrial	37,000	100%	50	8
Total				25

(Kelly, 2013) (AESO), Jacobs Consultancy Analysis

We estimated the potential electricity generated by utility-scale photovoltaic systems by assuming an installation density of 8 ha/MW (Kelly, 2013) and assuming that all crop and pastureland in Alberta could be used to install solar PV arrays. Clearly, this is an untenable assumption, but the calculation is intended to show the total potential available production for the purposes of comparing that number to the total electricity demand in Alberta.

Table 5.21 shows the estimate of electricity that could be generated by solar PV utility-scale arrays.

Table 5.21
Estimate of Solar PV Power Generation

Element	
Available Land, hectare (Cultivated Land + Pasture)	20 million ha
Solar PV Density, MW installed / ha	0.31
Insolation, MWh / MW	1,200
Total Available Power, PJ	26,000
Energy Density, GJ/ha	1,300

Table 5.22 compares potential solar PV generation in Alberta with Alberta consumption. Distributed solar PV has a limited ability to provide power to Alberta. However, utility-scale PV

solar installed in most of the white space could potentially provide a significant amount of power to the Province. If the installation of solar PV were on only 10% of this area, the potential to supply Alberta with electricity would still be high. However, the wide variation in summer-winter daylight requires significant back up power that would be idled in the summer.

Table 5.22
Percent of Total Consumption, Solar PV Power Generation

	Estimated Generation	% of Total Alberta Consumption
Distributed Solar PV, GWh/yr	6,900	9 %
Utility-Scale Solar PV, GWh/yr	7,300,000	9700 %

Net Energy Ratio— Solar PV

In our assumptions, the net energy consumed does not include the energy required to create the solar cells or the modules. Therefore the net energy consumed is very small compared to the energy commodity produced. The net energy consumed in the production of solar photovoltaic systems is significant but has been reduced by improvements in cell efficiency and in improved manufacturing techniques. For example, the efficiency of a CdTe module improved by 20% from 2006 to 2009, which translates into lower energy inputs.

The net energy ratio is the ratio of the energy in the commodity versus the energy to produce the commodity plus energy in the resource. Since we are not including the energy to build the plant, the energy to the produce the commodity is very low and the net energy ratio becomes the energy in the commodity / energy in the resource. The Net Energy Ratio for solar PV is shown in Table 5.23.

Table 5.23
Net Energy Ratio for Solar PV

	Solar PV - Distributed	Solar PV – Utility-Scale
Cell efficiency	13%	13%
Conversion efficiency	77%	77%
Line losses	0	3.4%
Overall efficiency = net energy ratio	10%	9.7%

In the pathway for distributed solar PV cases, there is little land use as the units are typically mounted on top of existing buildings such as home rooftops or barns.

In the case of utility-scale units, the land use is associated with the use of land for the installation of the modules. Land use is affected by the use of thin film as compared to crystalline-silicon modules. Thin-film modules typically have a higher area footprint than crystalline-silicon modules. Systems can also be installed with a tracking function that enables the modules to follow the sun's pathway to increase energy output per system. Tracking systems typically have a larger footprint due to the additional space between units that is needed so that the modules do not shade each other. In this analysis, it has been assumed that the modules are installed at a density of 8 MW/acre. With a solar insolation of 1,200 kWh/KW, this results in a land density of 750 ha/PJ.

Technology Improvements—Solar PV

Incremental Improvement— Incremental technology improvements in solar PV technology are directed to:

- Optimize PV cell efficiency, stability, lifetime and electricity yield
- Improve manufacturing productivity and cost reduction
- Reduce environmental impacts such as the energy for raw material processing, increase component recycling and reduce use of scarce materials
- Improve solar forecasting methods
- Address battery / storage integration to reduce power fluctuation issues
- Incorporate solar materials into building surfaces

Breakthrough Technology— Breakthrough technologies are focused on novel materials that can substantially improve efficiencies such as dye sensitized cells, organic cells and nanotechnology.

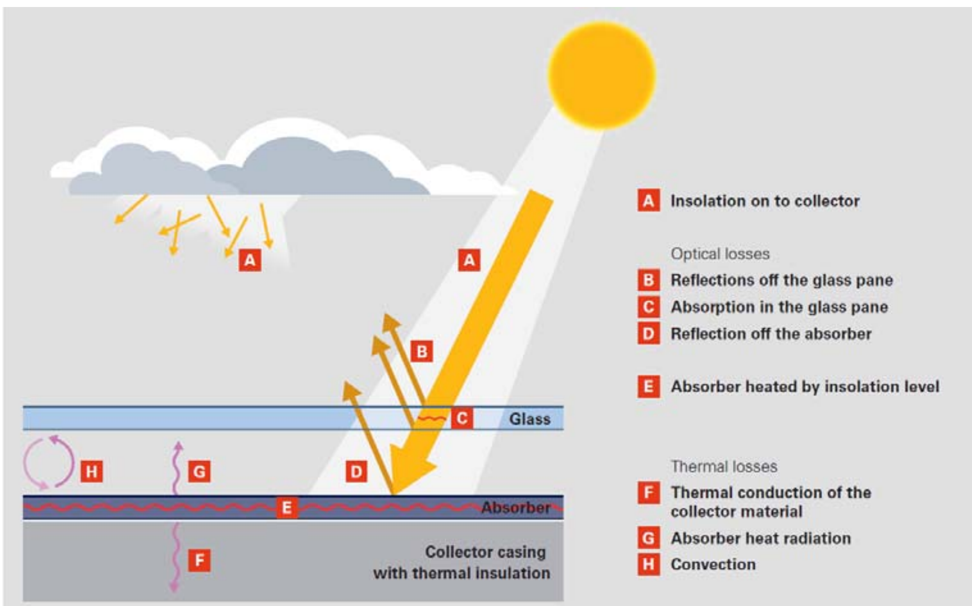
Solar Thermal Systems

Solar thermal technology used solar energy to heat transfer fluid such as water or glycol in panels for residential and industrial space heating and water heating. The systems are measured by the solar energy factor (SEF) which is the energy delivered by the system divided by the electrical or gas energy put into the system and the solar fraction (SF), less the portion of the total conventional hot water heating load (delivered energy and tank standby losses). The SEF typically ranges between 2 and 3 and the SF is typically 0.5–0.75. The physics of solar thermal heating are depicted in Figure 5.50.

Solar thermal collector efficiency is affected by multiple factors (Trier, 2012):

- Ambient temperature and the temperature of the heat transfer fluid
- Angle of incidence of the light on the collector
- Collector area
- Insulation of the collector to minimize thermal losses
- Fluid flow rates through the collector
- Solar irradiation

Figure 5.50
Solar Thermal Space Heating



(Trier, 2012)

There are solar thermal water heaters and space heaters sold throughout Alberta. In particular, the Drake Landing community in Okotoks, outside of Calgary, (Figure 5.51) includes highly energy-efficient homes with a sophisticated solar thermal system and centralized storage. The community reportedly achieves 97% of space heating requirements from solar thermal heating.

Figure 5.51
Solar Thermal – Drake Landing, Okotoks, Alberta

Available Energy— Solar Thermal

Heat output in Alberta from solar thermal for residential heating can be estimated as shown in Table 5.24. Typical solar thermal collection potentially could trim 3-6% from residential energy use (0.2-0.3% of overall Alberta energy demand).

Table 5.24
Available Energy – Solar Thermal – Residential Hot Water Heating

	# of Homes	% Available	Typical Installation Size (kWh/house/day)	Power Output (PJ/yr)
Residential	1.4 million	50 % south facing, 30% shaded	5 – 9	1.5 – 2.5

Technology Improvements—Solar Thermal

Incremental Improvement— Technology improvements in solar thermal technology are focused on improving efficiency, reducing cost and increasing the ease of installation to make it easier for homeowners to install systems. These improvements include:

- Reduce cost and weight through manufacturing improvements and new materials
- New polymer materials to reduce deterioration from UV light
- Solar thermal collection capabilities in the building walls
- Hybrid PV/thermal systems
- Improved systems to be able to supply heat for industrial applications
- Solar cooling technology
- Large scale storage systems

Breakthrough Technology— Completely new configurations for small-scale solar thermal installations might provide the efficiency and performance of industrial-scale concentrated solar thermal technology.

Metrics— Solar PV and Solar Thermal

Table 5.25 summarizes the conversion efficiencies for sunlight to electricity or heat.

Table 5.25
Energy Summary— Conversion of Sunlight to Electricity and Heat

Solar Pathways	Factors	Power, GJ/hr
Solar Photovoltaic Distributed		
Solar Energy	Solar insolation, efficiency of solar cells, geometry of installation, cell temperature	10,000
Cell efficiency	Function of cell chemistry 12 – 14%	(8,700)
Efficiency losses	Mechanical, transmission, parasitic energy consumption, planned/unplanned outages, dispatch, temperature effects, age effects - 77% derate factor for the cell efficiency	(300)
Line Losses to City Gate	Depends on distance and voltage	0
Electrical Power Delivered		1,000
Solar PV Utility		
Solar Energy	Solar insolation, efficiency of solar cells, geometry of installation, cell temperature	10,000
Cell efficiency	Function of cell chemistry 12 – 14%	(8,700)
Efficiency losses	Mechanical, transmission, parasitic energy consumption, planned/unplanned outages, dispatch, temperature effects, age effects – 77% derate factor	(300)
Line Losses to City Gate	Depends on distance and voltage	(30)
Electrical Power Delivered		970
Solar Thermal		
Solar Energy	Solar insolation, geometry of installation,	10,000
Collector efficiency	Highly dependent on system temperatures and system design, efficiency for evacuated tube collector systems for hot water and space heating approximately 55 – 70%	(3,700)
System efficiency	Losses due to pipe losses and tank losses, function of operating temperature and system design –derating factor of 77% estimated for combination hot water and space heating application	(1,500)
Heat Delivered		4,800

Figure 5.52 shows the pathway from solar energy to electricity by means of photovoltaic cells or solar thermal.

Figure 5.52
Energy Pathway – Solar PV or Solar Thermal

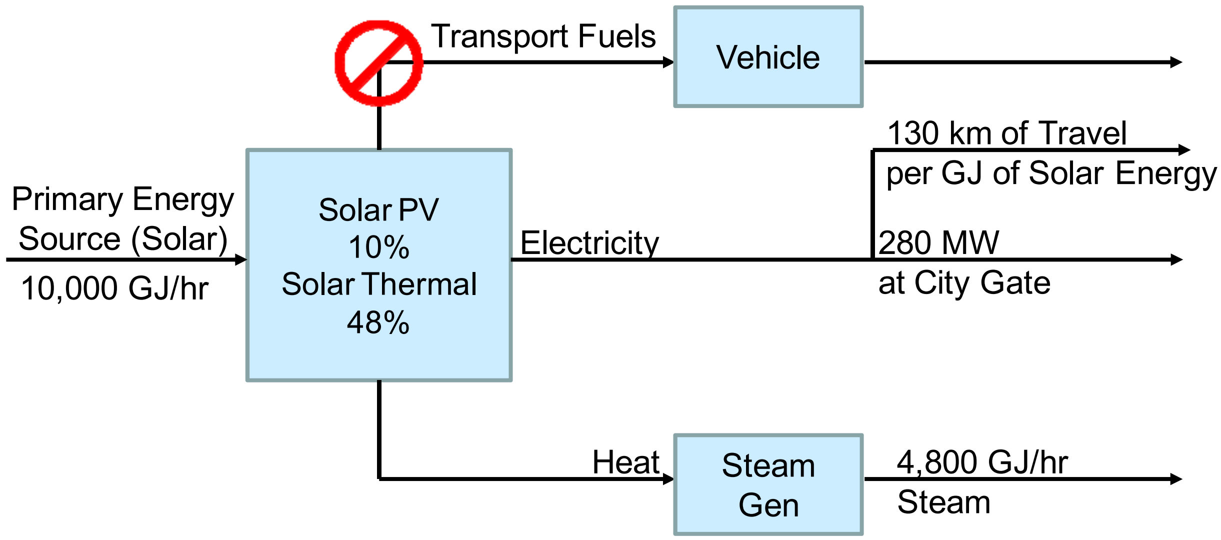


Table 5.25a provides the metrics summary for the three solar energy pathways examined in the Study, distributed solar PV, utility-scale solar PV, and solar thermal.

Table 5.25a
Solar Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Solar PV Distributed	Solar PV Utility	Solar Thermal
Energy Type						
	Type of Source			Flow	Flow	Flow
Production and Capacity						
	Remaining Established Reserve Potential, Primary Source	PJ		Not applicable	Not applicable	Not applicable
	Annual Production of Energy from Primary Source					
	Actual Annual Production, Primary Source	PJ/yr		Not available	Not applicable	Not available
	Available Commodity Production Capacity (Current Installed Capacity)					
	Commodity - Conventional Units					
	Electricity	MW		3.2	Not applicable	
	Heat	PJ/yr				Not available
	Commodity - PJ/yr					
	Electricity	PJ/yr		Not available	Not applicable	
	Heat	PJ/yr				Not available
	Current actual commodity produced					
	Commodity - Conventional Units					
	Transportation Fuels	MM Bbls/yr	86			
	Electricity	GWh/yr	75,500	Not available	Not applicable	
	Heat	PJ/yr	1,260			Not available
	Commodity - PJ/yr					
	Transportation Fuels	PJ/yr	468			
	Electricity	PJ/yr	272	Not available	Not applicable	
	Heat	PJ/yr	1,260			Not available
	Available Commodity % of Alberta Consumption					
	Electricity	%		Not available	Not applicable	
	Heat	%				Not available
	Commodity Production if all Alberta Primary Source is Converted to Commodity					
	Commodity - Conventional Units					
	Electricity	GWh/yr		6,900	7,300,000	
	Heat	PJ/yr				3 -4
	Commodity - PJ/yr					
	Electricity	PJ/yr		25	26,000	
	Heat	PJ/yr				3 -4
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption					
	Electricity	%		9	9700	
	Heat	%				3

Table 5.25a (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Solar PV Distributed	Solar PV Utility	Solar Thermal
Energy Density of Energy Source						
	Primary Source (LHV)	MJ/kg		Not applicable	Not applicable	Not applicable
	Primary Source (HHV)	MJ/kg		Not applicable	Not applicable	Not applicable
	Primary Source (LHV) - from ore	MJ/kg		Not applicable	Not applicable	Not applicable
	Transportation Fuel - weighted average	MJ/kg		Not applicable	Not applicable	Not applicable
Efficiency and Energy Consumption						
	Energy Consumption					
	Electricity	GJ/GJ		nil	nil	
	Heat	GJ/GJ				nil
	Net Energy Ratio					
	Electricity	GJ/GJ		0.10	0.097	
	Heat	GJ/GJ				not available
	Electricity Conversion					
	Efficiency of power plant conversion	%		10	10	
	Electricity	kW-hr/GJ Primary Source		28	27	
	Distance Delivered					
	Distance delivered from Electricity	km/GJ Primary Source		132	127	
	Distance delivered from Transportation Fuels	km/GJ Primary Source		not applicable	not applicable	not applicable
Environmental Metrics						
	GHG					
	Electricity	g CO2e/MJ		nil	nil	
	Heat	g CO2e/MJ				nil
	Land Use					
	Electricity	ha/PJ		nil	750	
	Heat	ha/PJ				nil
	Water Use					
	Electricity	m3/GJ		nil	nil	
	Heat	m3/GJ				nil
	Air emissions					
	Electricity	g/MJ		nil	nil	
	Heat	g/MJ				nil
	Solids emissions					
	Electricity	g/MJ		nil	nil	
	Heat	g/MJ				nil

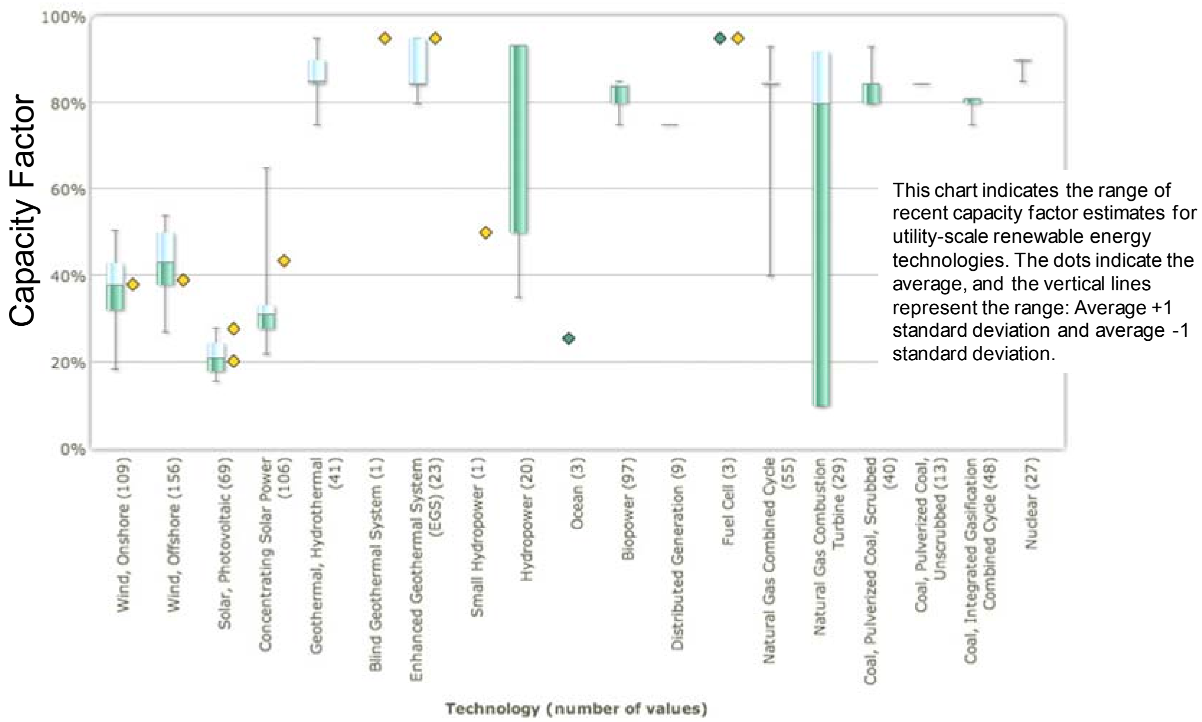
(Kelly, 2013), Jacobs Consultancy Analysis

Geothermal Energy and Other Sources of Low Level Heat

Geothermal energy has significant potential to deliver energy for electricity generation and space heating. Geothermal energy comes from two sources, which are heat released from decomposition of radioactive material, and heat released from the earth's mantle and core. The average heat flux from the earth is 59 MW/m^2 which is more than enough to supply the world's energy needs (MIT, 2006). However, the availability of heat sources that can be expoited for electricity generation depends on geology and therefore varies from region to region.

Geothermal electricity generation is expected to have capacity factors in the range of those from the generation of electricity from fossil fuels, which makes geothermal a potential replacement for base load power from coal and natural gas (NREL). Capacity factors for different sources of electricity are shown in Figure 5.53.

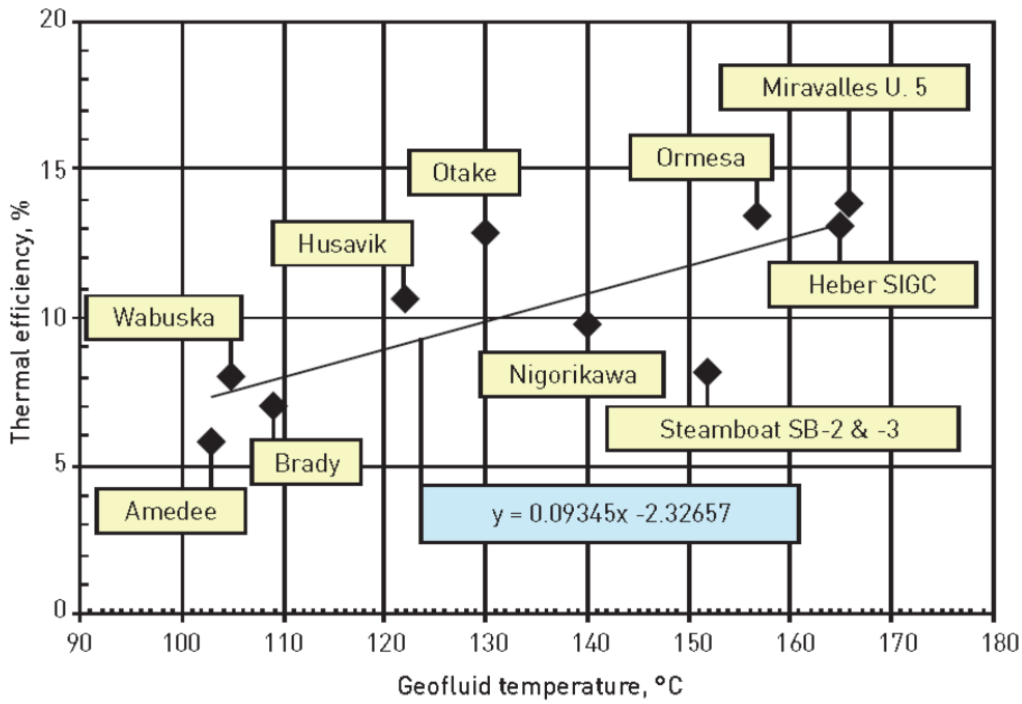
Figure 5.53
Capacity Factors for Electricity Generation (from NREL Utility Energy)



The most economical generation of electricty from geothermal sources is achieved with resources that are greater than 150°C in temperature. However, it is possible to generate electricity with resources that are as low as 80°C using the right working fluid in a binary system. Geothermal resource temperatures increase with depth. However, the economic and technical limit on drilling to tap geothermal sources is currently around 10 km (MIT, 2006).

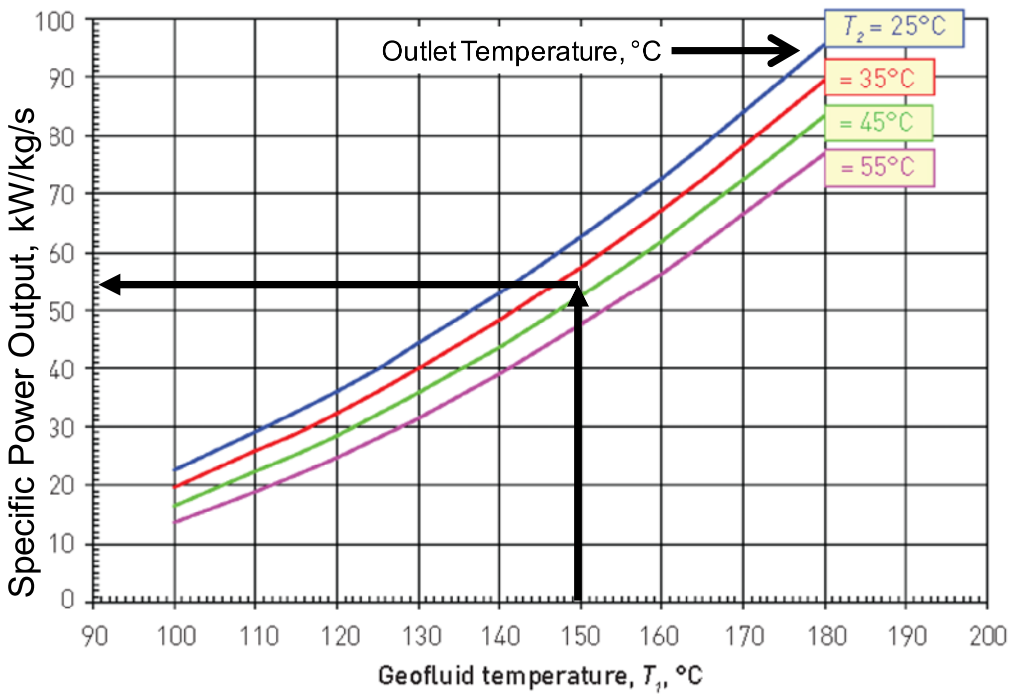
Thermal efficiency of electricity generation at different commercial geothermal sites is shown in Figure 5.54. (MIT, 2006) Thermal efficiency increases with temperature of the geofluid.

Figure 5.54
Correlation of Binary Plant Cycle Thermal Efficiency with Geofluid Temperature



Electricity generation as a function of the temperature of the geofluid source is shown in Figure 5.55 for different temperatures of the outlet fluid after energy extraction (MIT, 2006). This figure enables estimation of the fluid flow needed for a specific power output. For example, a geofluid with inlet temperature of 150°C and outlet temperature of 35°C can deliver 58 kw per 1 kg/sec of geofluid fluid flow. Thus, a 10 MW plant will require geofluid flow of 10,335 l/min. Extrapolating the data in Figure 5.55 indicates that to generate 10 MW of electricity from a 90°C temperature source will require a flow of 600,000 l/min (36,000 m3/hr). The electricity to circulate this fluid will be significant and could be greater than the electricity generated.

Figure 5.55
Specific Power from Low to Moderate Temperature Sources



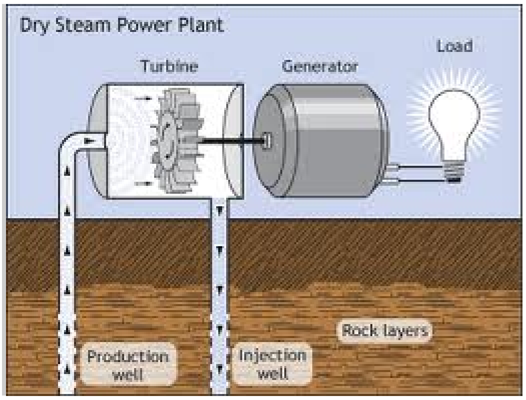
This liquid flow can be from the reservoir itself. However, if there is insufficient influx of new fluid, the reservoir will lose heat faster than it is regenerated and hence it will decline as a source of heat.

If the number of wells that can deliver a high rate of flow at the desired temperature is limited, it may be necessary to drill more wells or stimulate flow in the reservoir by opening channels and pores via controlled reservoir fracturing. This process is called Enhanced Geothermal Systems, or EGS (MIT, 2006). In EGS the reservoir is carefully mapped, injector and collector wells drilled, and the reservoir fractured in a controlled manner to increase porosity between the injector and collector wells. The spacing between injector and collector wells is typically between 800 and 1000 m. In production mode, fluid (usually water) is pumped into the injector well, heated by the reservoir, and then recovered in the collector well(s).

Electrical energy can be extracted from geothermal sources in the following ways: dry steam plants, flash steam plants, and binary cycle plants. A brief description of these process plants follows (USDOE, 2012):

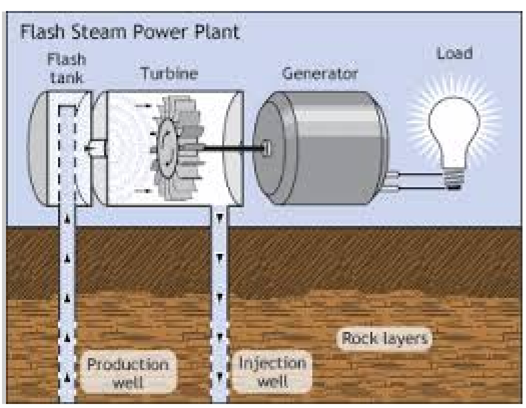
Dry Steam Power Plant - Dry steam plants use hydrothermal fluids, which are primarily steam generated in the reservoir. Steam travels directly to a turbine, which drives a generator that produces electricity (Figure 5.56). Dry steam plants emit only excess steam and very minor amounts of gases. Dry steam power plants systems were the first type of geothermal power generation plants built (Lardarello in Italy in 1904). Dry steam technology is used at The Geysers in northern California, the world's largest single source of geothermal power.

Figure 5.56
Dry Steam Power Plant Schematic



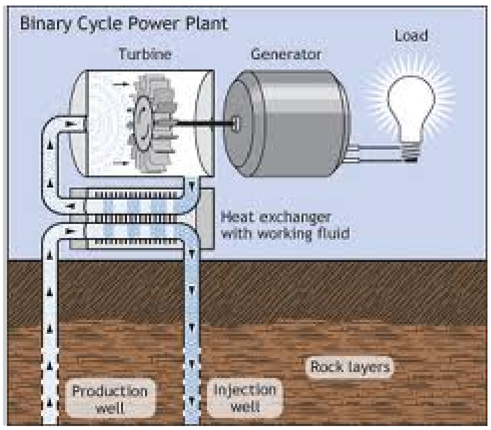
Flash Steam Power Plant - Flash steam plants are the most common type of geothermal power generation plants in operation today. Fluid at temperatures greater than 180°C is pumped under high pressure into a tank at the surface where the pressure is reduced causing some of the fluid to rapidly vaporize, or flash. The steam vapor drives a turbine, which drives a generator. Any liquid remaining in the tank can be flashed again at lower pressure in a second tank to further extract energy (Figure 5.57).

Figure 5.57
FlashSteam Power Plant Schematic



Binary Cycle Power Plant - Binary cycle geothermal power generation plants differ from Dry Steam and Flash Steam systems in that the water or steam from the geothermal reservoir never comes in contact with the turbine/generator units. Low to moderately heated geothermal fluid, typically below 200°C exchanges heat with a secondary (hence, "binary") working fluid that has a much lower boiling point than water. Heat from the geothermal fluid causes the secondary fluid to flash to vapor, which then drives the turbines and subsequently, the generators (Figure 5.58). Binary cycle power plants are closed-loop systems and virtually nothing (except water vapor) is emitted to the atmosphere. Because most geothermal resources are below 200°C it is expected that growth in geothermal power plants will come mainly from binary-cycle plants.

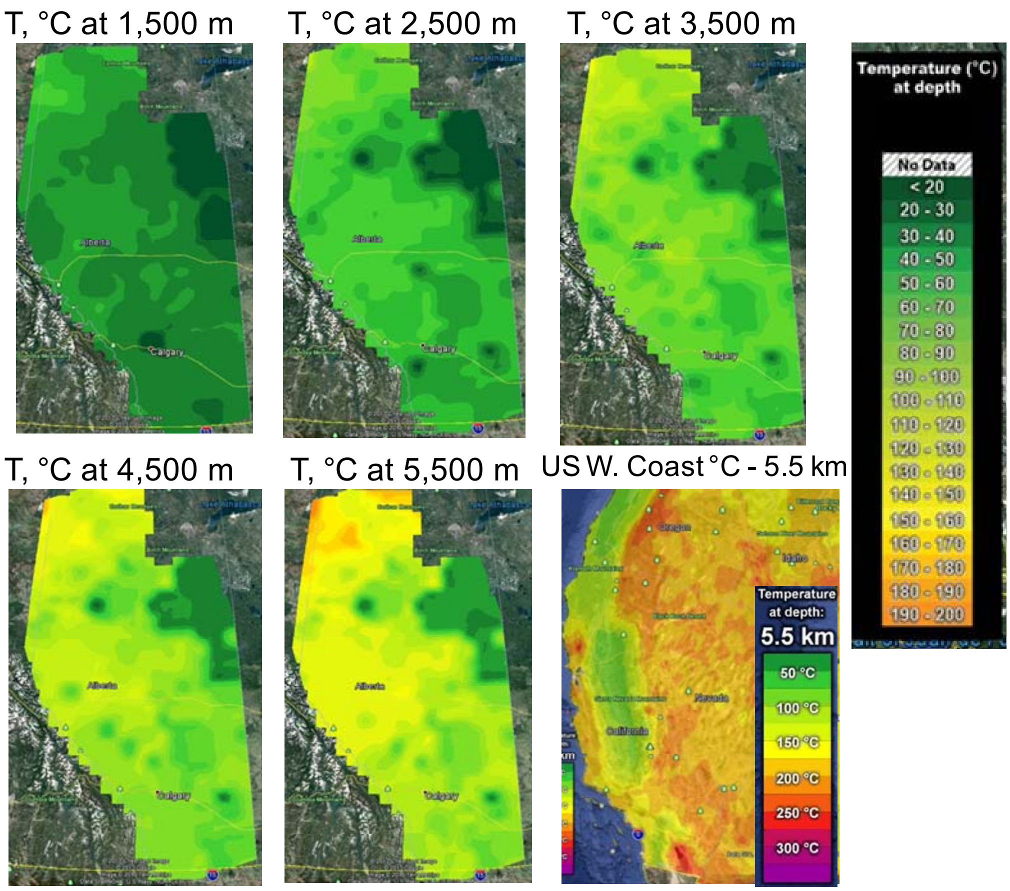
Figure 5.58
Binary Power Plant Schematic



Temperatures in Alberta at different depths supplied by CanGea and taken from Google Earth are shown in Figure 5.59 (CanGea, 2013). It is not until depths greater than 4,500 m that the temperature will be greater than 150°C.. For reference, the temperature map of the US West Coast at 5,500 m is included and shows that this region has greater potential for geothermal energy development than Alberta. The maps show somewhat higher temperatures in northwestern Alberta near the border with the Northwest Territories and British Columbia. These regions may offer greater potential for developing geothermal sources than those near the population centers in central Alberta.

As discussed earlier, binary cycle plants are necessary to generate electricity from resources below 150°C. With lower temperature resources more wells or use of EGS to increase flow will be needed to generate the same amount of electricity as from a resource at 150°C.

Figure 5.59
Geothermal Map of Alberta and US West Coast

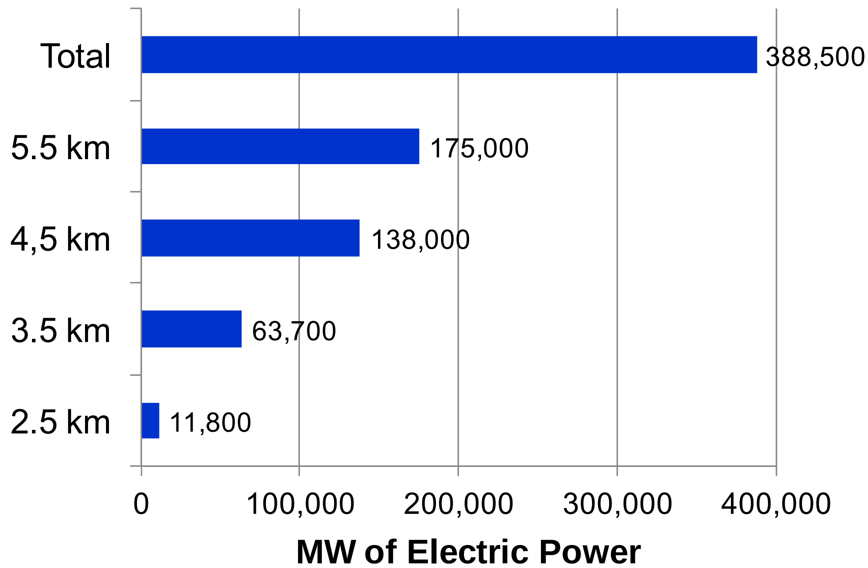


Because Alberta does not have significant high temperature resources, the potential for electricity generation via the dry steam process or flash steam production is minimal. It is therefore most likely that energy production from geothermal resources in Alberta would be from binary cycle plants that recover heat from fluids produced from on purpose wells drilled to recover this heat and from fluids produced in oil and gas extraction. .

Electricity Potential from Geothermal Energy

The technical potential for electricity generation in Alberta is shown in Figure 5.60. We assume 14% recovery of energy. (CanGea, 2013) Technical potential is “the fraction of the theoretical potential that can be used under the existing technical restrictions… structural and ecologic restrictions as well as legal and regulatory allowances” (Rybach, 2010)

Figure 5.60
Technical Potential for Geothermal Electricity in Alberta



The maximum pontential for electricity generation in Alberta could be as high as 388 GW, or 12,250 PJ/yr (CanGea, 2013). The demand for electricity in Alberta in 2012 was around 272 PJ/yr. However, generation of this amount of electricity from geothermal sources would require many high-capacity wells that produce at least 5 MW/well and thus require flow rates of 30-100 kg/sec flow. Achieving this degree of electricity generation may require a large number of wells or formation fracturing to enable heat extraction.

There have been no commercial demonstrations of geothermal generation of electricity in Alberta. The absence of geothermal demonstration plants is not because the technology is unproven but because of economic and regulatory factors. (Cangea private communication) At this time, although we find geothermal energy could have significant potential to generate electricity, we do not anticipate that it will generate much electricity for Alberta in the time frame of the Study. Over a longer time horizon, geothermal may well become an important source of electricity for Alberta.

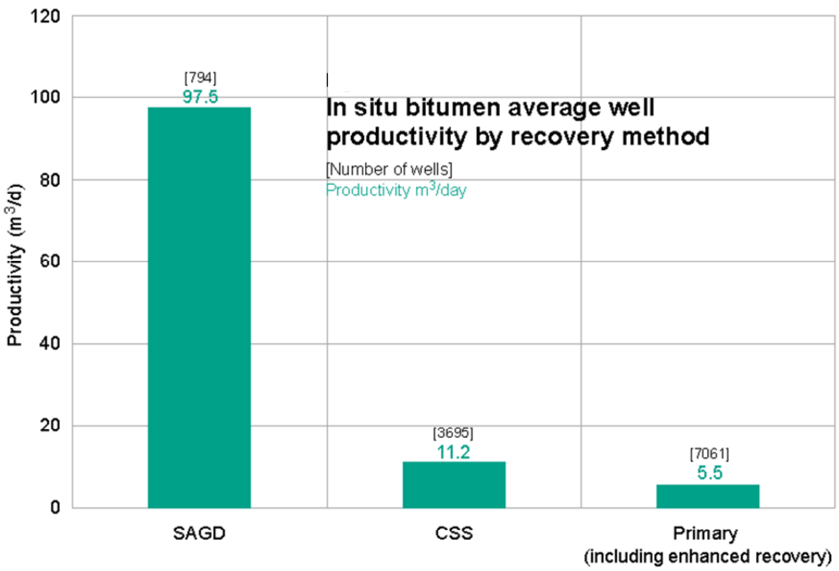
Electricity from Other Low Level Sources of Waste Heat

Other sources of electricity generation include the capture of waste heat from in situ bitumen production, from refineries and upgraders, and from on site heat recovery in carbon black manufacture.

Electricity from In Situ Bitumen Production

Figure 5.61 shows the average rate of bitumen production from each well and the number of production wells for SAGD, CSS, and primary methods of in situ bitumen recovery. (ERCB, 2013) We can use these flow rates, an assumed steam to oil ratio, and an assumed temperature in the reservoir to estimate the amount of electricity that potentially could be generated from the fluid recovered from the well.

Figure 5.61
In Situ Bitumen Well Average Production Rates

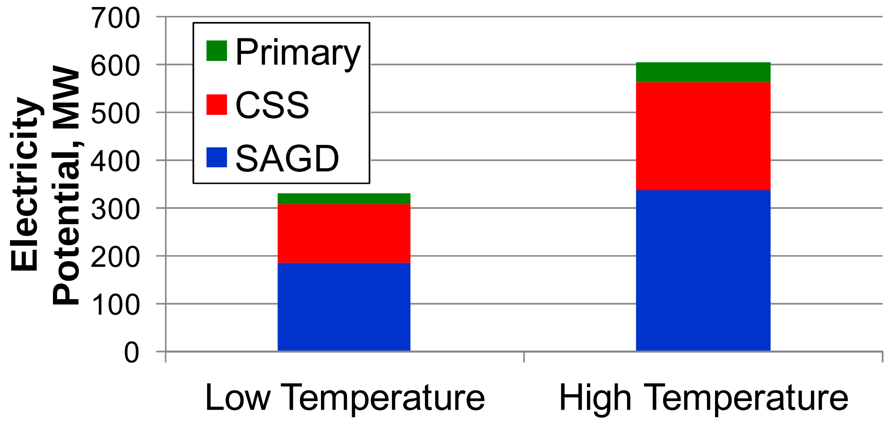


Source: ST98-2013 - Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022, ERCB, 2013

Figure 5.62 shows two estimates for electricity generation potential from fluids recovered from in situ bitumen production. We assumed 2.9 SOR for SAGD, and 3.95 SOR for CSS, which are in the range of historical SORs for SAGD and CSS for all facilities reported to ERCB in 2010-2011. (AER, 2010-2013) We estimated the potential for electricity generation at two conditions: the low temperature conditions assume that the inlet to the heat recovery binary plant is at 150 °C and the outlet is at 45 °C; the high temperature conditions assume 180 °C in and 20 °C out.

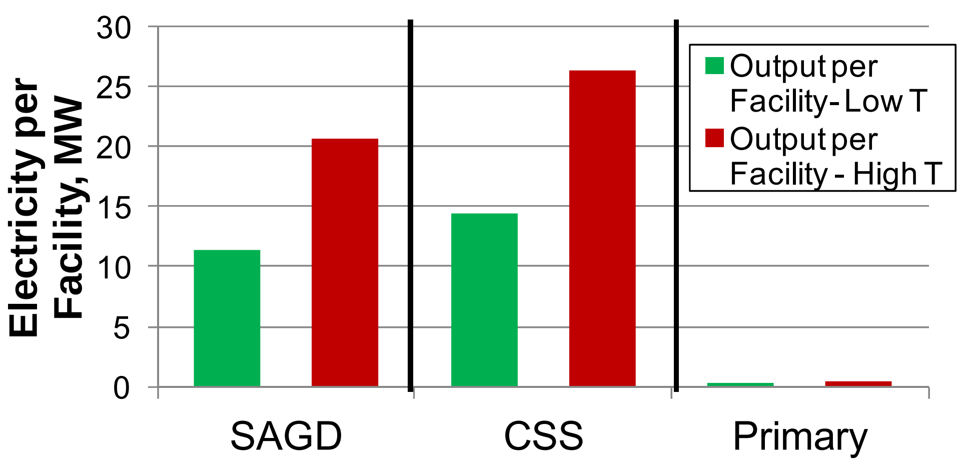
We used the correlations in Figure 5.55 to estimate the potential to generate electricty from in situ bitumen production shown in Figure 5.62. Based on this assessment, the maximum electricity potential from heat recovery from in situ bitumen production in Alberta is around 600 MW at the high temperature conditions and around 300 MW at the low temperature conditions.

Figure 5.62
Electricity Potential from In Situ Production from Waste Heat



These levels of electricity generation are typical of a small to medium size dedicated power plant. The issue is that it will take many in situ bitumen production sites to generate this amount of electricity. As shown in Figure 5.63, a typical 30 KBPD in situ producton site will generate electricity in the range of 10-20 MW for SAGD and 15-25 MW for CSS depending on the temperatures and flow rate of fluids recovered from the well. These are upper end estimates of electricity generation; most in situ production facilities are quite heat integrated and there is not much waste heat available to generate electricity.

Figure 5.63
Estimated Electricity Production per Facility from Potential Waste Heat



Electricity from Hydrocarbon Processing Plants

Process units in refineries and upgraders also could supply waste heat for electricty generation.. Typical levels of waste heat from process units used in refineries and upgraders are shown in Table 5.26. We have assumed that the energy available is from process unit low level heat (not from furnace stacks).

Table 5.26
Low Level Heat Available from Typical Refining Process Units

	Low Level Waste Heat	Electricity (10% Heat Recovery)
	MJ/hr/ BPSD of Crude Capacity	kW/BPSD of Crude Capacity
Crude/Vacuum	800	0.024
Coker	100	0.003
FCC	900	0.024
Platformer	100	0.004
Boilers	200	0.007
Total	2,100	0.062

Based on the level of waste heat that could be made available, refineries could supply as much heat as 2,100 MJ/hr per BPD of crude capacity and upgraders could supply as much heat as 1,100 MJ/hr per BPSD of bitumen capacity (no FCC or Platformer). If we assume that 10% of this heat can be recovered for electricity generation using binary systems, we obtain the results shown in Tables 5.27 and 5.28. Using these results, we estimate that the five upgraders in Alberta could supply 45 MW of electricity (Table 5.27). The four Alberta refineries could supply 26 MW of electricity, assuming an 80% on stream factor (Table 5.28).

Table 5.27
Potential Electricity from Upgrader Waste Heat

Project Name	Location	Capacity (bbl/d) Bitumen	MW
Athabasca Oil Sands Project - Shell Scotford	Fort Saskatchewan	255,000	9
Suncor Base and Millennium	Fort McMurray	440,000	15
Syncrude Mildred Lake	Fort McMurray	407,000	14
Nexen Long Lake	Fort McMurray	72,000	2
Canadian Natural Resources Ltd Horizon	Fort McMurray	135,000	5
Total		1,309,000	45

Table 5.28
Potential Electricity from Refinery Waste Heat

Company	Location	Capacity (bbl/d)	MW
Suncor	Edmonton	135,000	8
Imperial Oil	Edmonton	187,200	12
Shell Canada	Scotford	100,000	6
Total		422,200	26

Other facilities in Alberta currently use waste heat to generate elecricity. The CanCarb carbon black plant can generate as much as 42 MW. The Manning Diversed Forest Products Plant can generate as much as 2 MW of power. The results are summarized in Table 5.29.

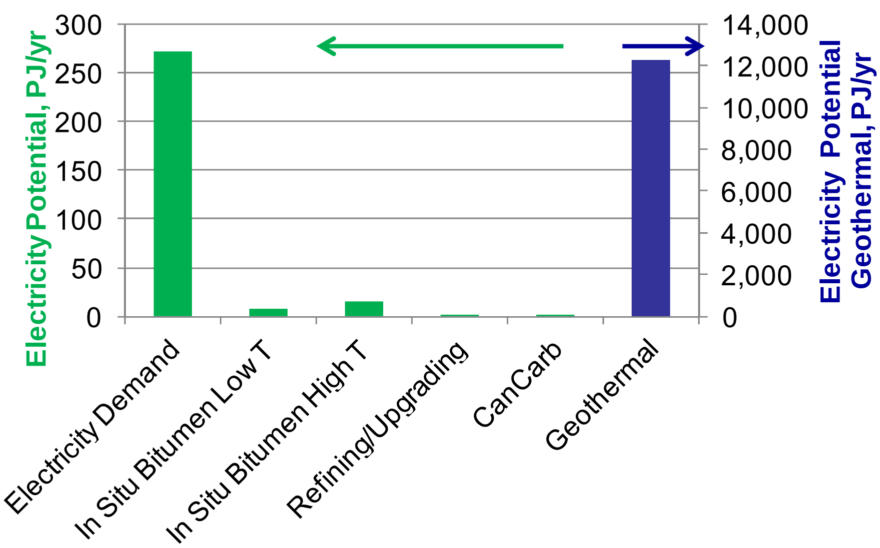
Table 5.29
Electricity Generation from Existing and Proposed Industrial Plant Waste Heat

Company	Location	Pathway	Energy Source	Capacity (MW)	Status
Cancarb	Medicine Hat	Waste Heat Recovery	Carbon Black Manufacture	42	Operating
Manning Diversified Forest Products		Organic Rankine Cycle	Waste Heat	2	Proposed

Electricity generation from CanCarb ~ 1.0 PJ/yr*
*Assumes 80% on stream factor

The potential for electricty generation from waste heat and from geothermal sources in Alberta are compared with the demand for electricity in Figure 5.64.

Figure 5.64
Alberta Electricity Potential from Waste Heat



While geothermal has significant potential to supply far more electricity than Alberta's current needs, this technology has not been commercialized in Alberta. Furthermore, we conclude that geothermal will not contribute significant amounts of electricity in the time frame of the Study.

Other sources of electricity from available waste heat are not signficant in the context of Alberta's demand for electricity. We note that sources of electricty from geothermal and from waste heat likely would be small in size, which could drive up the costs for this electricity compared to other sources that have lower costs per kW of installed capacity.

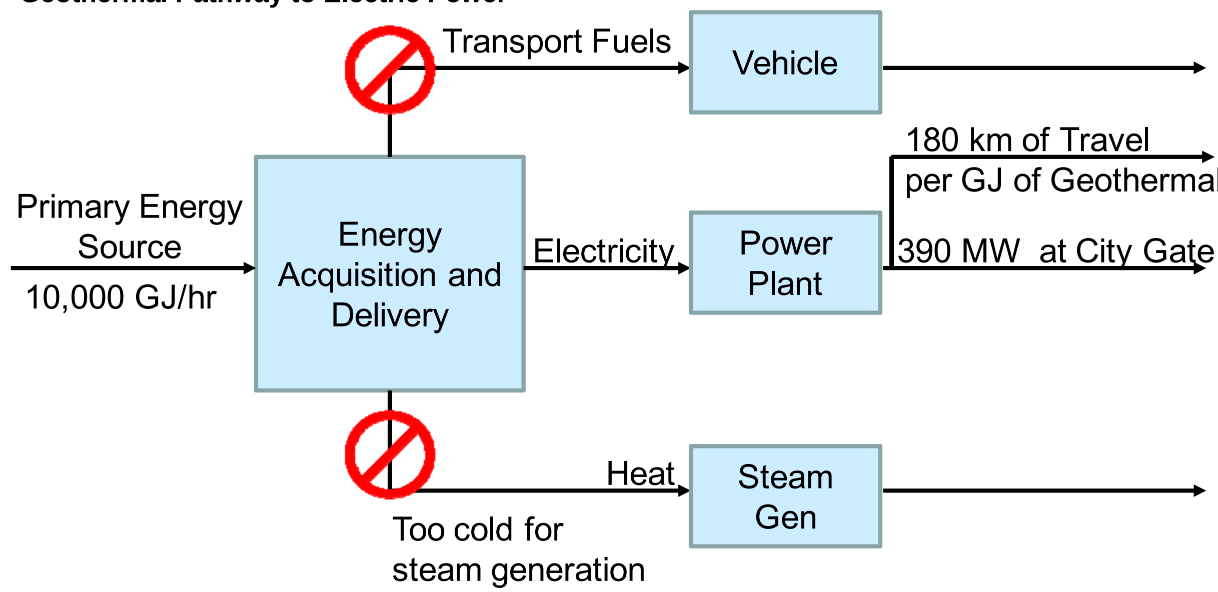
Table 5.30 summarizes the efficiency of the most likely option for geothermal power, conversion to electricity.

Table 5.30
Energy Summary— Conversion of Geothermal Energy to Electricity

Geothermal	Factors		Geothermal
Power from geothermal	Temperature of reservoir	GJ/hr	10,000
Efficiency of power generation	Rankine engine - assume 150 °C inlet		15%
	Line loss		3.40%
Electricity	Electric power	GJ/hr	1,449
	Electric power	MW	390
	Distance for electric vehicle	km/GJ	180

Figure 5.65 depicts the pathway from geothermal power to electricity.

Figure 5.65
Geothermal Pathway to Electric Power



Metrics for geothermal and waste heat from the sources discussed above are summarized in Table 5.31.

Table 5.31
Geothermal Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Geothermal
Energy Type				
	Type of Source			Stock/Flow
	Actual Annual Production, Primary Source	PJ/yr		nil
	Electricity	MW		nil
	Electricity	PJ/yr		nil
	Current actual commodity produced			
	Commodity - Conventional Units			
	Transportation Fuels	MM Bbls/yr	86	
	Electricity	GWh/yr	75,500	
	Heat	PJ/yr	1,260	
	Commodity - PJ/yr			
	Transportation Fuels	PJ/yr	468	
	Electricity	PJ/yr	272	
	Heat	PJ/yr	1,260	
	Available Commodity % of Alberta Consumption			
	Electricity	%		nil
	Heat	%		nil
	Commodity Production if all Alberta Primary Source is Converted to Commodity			
	Commodity - Conventional Units			
	Electricity	GWh/yr		3,403,000
	Commodity - PJ/yr			
	Electricity	PJ/yr		12,250
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption			
	Electricity	%		4,510
Energy Density of Energy Source				
	Primary Source (LHV)	MJ/kg		Not Applicable

Table 5.31 cont.

Metric Type	Metric	Primary Source	Alberta Total Demand	Geothermal
Efficiency and Energy Consumption				
	Net Energy Ratio			
	Transportation Fuels	GJ/GJ		Not Applicable
	Electricity	GJ/GJ		Not Applicable
	Heat	GJ/GJ		Not Applicable
	Electricity Conversion			
	Efficiency of power plant conversion	%		15
	Electricity	kW-hr/GJ Primary Source		39
	Distance Delivered			
	Distance delivered from Electricity	km/GJ Primary Source		185
	Distance delivered from Transportation Fuels	km/GJ Primary Source		
Environmental Metrics				
	GHG			
	Transportation Fuels	g CO2e/MJ		Not Applicable
	Electricity	g CO2e/MJ		nil
	Heat	g CO2e/MJ		nil
	Land Use			
	Electricity	ha/PJ		nil
	Heat	ha/PJ		nil
	Water Use			
	Electricity	m3/GJ		0.32
	Air emissions			
	Transportation Fuels	g/MJ		Not Available
	Electricity	g/MJ		Not Available
	Heat	g/MJ		Not Available
	Solids emissions			
	Transportation Fuels	g/MJ		Not Available
	Electricity	g/MJ		Not Available
	Heat	g/MJ		Not Available

Geothermal Heat Pumps for Space Heating

Geothermal heat pumps can use low level heat available at shallow depths underground or from wells and streams to generate space heating. The following discussion is from *Feasibility of Ground Source Heat Pumps in Alberta*. (Miller, 2008)

> "Conventional space heating in Alberta relies on burning natural gas to heat air which is distributed throughout a building. An alternative that has been gaining popularity due to improving economics over the past few years relies on the natural heat in the earth to heat our buildings. Ground source heat pumps are sometimes considered a viable alternative for space heating.
>
> The heat pump has been used in various regions of Canada and Europe for many years. A ground source heat pump (GSHP) is a device that extracts heat from the earth beneath the frost line or from a body of water and transfers it to a building for heating in winter, and reverses the process to cool buildings in summer. This type of system is also known as geothermal energy. Heat pumps transfer heat by circulating a refrigerant through a cycle of evaporation and condensation, similar to the operation of a refrigerator. A compressor pumps the refrigerant between two heat exchanger coils. In one coil, the refrigerant is evaporated at low pressure and absorbs heat from its surroundings. The refrigerant is then compressed as it transfers to the other coil, where it condenses at high pressure and releases heat. The major advantage of the GSHP is that it does not burn fossil fuels on site. Electricity is used to operate the system, however the inherent energy in the heat extracted from the earth is much higher than the electricity required to drive the system components.
>
> The underground piping system used to transfer heat can be either an open system or closed loop. An open system takes advantage of the heat retained in an underground or open body of water. The water is drawn up through a well directly or from an open body of water to the heat exchanger, where heat is extracted, then discharged either to an above-ground body of water, such as a stream or pond, or back to the same underground water body through a separate well. More common in most regions is the closed-loop system, which collects heat from below ground by means of a continuous loop of piping buried underground below the frost line. An antifreeze solution, chilled by the heat pump's heat exchange system to several degrees colder than the outside soil, circulates through the piping and absorbs heat from the surrounding soil, returning to the heat pump located inside the building.
>
> Heat pump economics are most attractive when there are both heating and air conditioning requirements, lower electricity prices compared to competing space heating alternatives, plus some provincial government financial assistance. Air conditioning is

not common in most of Alberta's existing residential dwellings, however it is more common in the SCI market, and thus the heat pump market would have the greatest potential for small commercial or institutional buildings in southern Alberta. The slow uptake of GSHPs in Alberta can be partially attributed to two factors. The first factor is the current pricing structure of natural gas and electricity in Alberta. Virtually all conventional space heating in Alberta is with natural gas, which continues to be relatively inexpensive as consumers are protected by the provincial government's natural gas cap [*sic*]. It is also important to note that GSHPs use electricity to drive the pump.

Secondly, the GSHP, as with any new competing technology for space heating, has to go head-to-head with the current technology, natural gas furnaces. At the residential level, there is a significant gap between the capital cost of a conventional gas furnace, whether mid-efficiency or high efficiency, and a GSHP system. Air conditioning has very low saturation levels in the Alberta residential market, and GSHPs provide both heating and air conditioning. Higher natural gas costs complemented by lower electricity costs would enhance heat pump economics. Some other non-financial barriers to market penetration have also been identified such as:

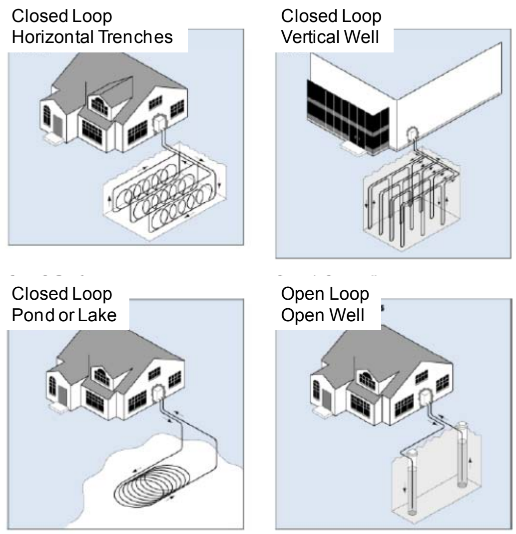
- Divisibility: the ability to try on a limited basis before full adoption
- Communicability: how well does the technology communicate benefits
- Compatibility: how closely does a GSHP system compare to conventional HVAC systems
- Complexity: how easy is it to understand both the benefits and features of the technology

Given the Alberta energy mix, it can largely be generalized that switching from conventional forced air furnaces to GSHPs in typical residential applications does not result in any GHG benefits. However, it is important to note that when electricity is purchased from renewable sources (i.e. wind power) there are significant GHG savings from switching from conventional forced air furnaces to GSHPs.

It is important to note that this analysis is for residential applications as commercial applications may have substantially different economics and GHG balance. It is also important to note that this analysis does not account for supplementary heating and cooling that may occur such as the use of portable AC units and fans during warm periods which have the potential to substantially increase electricity consumption and GHG emissions."

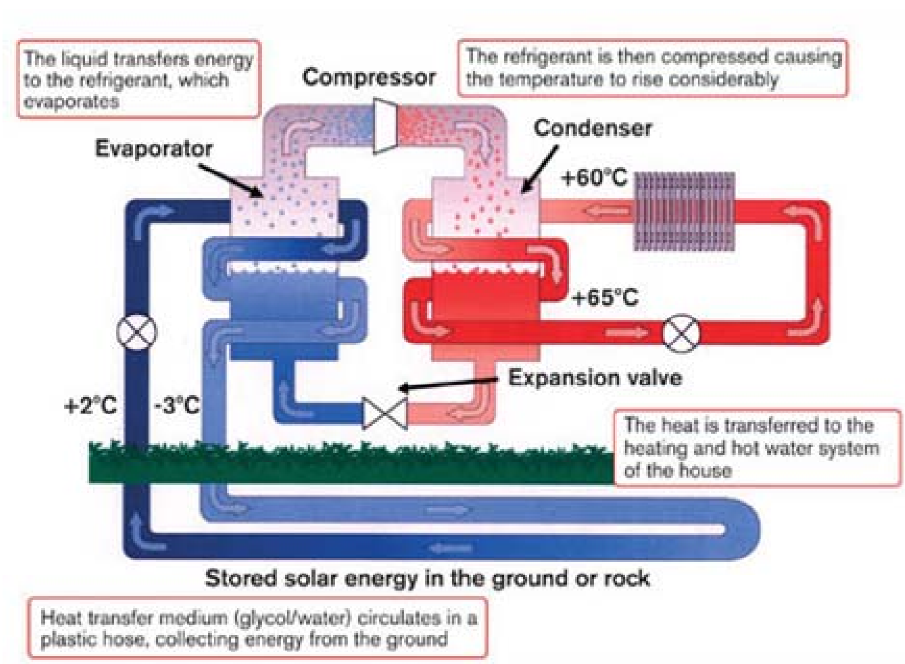
The four common configurations for ground source heat pumps are in Figure 5.66.

Figure 5.66
Types of Ground Source Heat Pump Systems



A schematic of a heat recovery in a ground source heat pump is shown in Figure 5.67.

Figure 5.67
Schematic of Heat Pump for Ground Based Geothermal Heating



Ground source heat pumps reduce the need for direct firing of fuel, such as natural gas for heating. However, ground source heat pumps require more electricity than conventional furnaces because of the need to compress the working fluid used to transfer heat.

Table 5.32 compares the energy use and GHG emissions for a medium and high efficiency conventional residential forced air furnace with the energy and GHG from a Ground Source Heat Pump. Because of the cold climate in Alberta, the Ground Source Heat Pump must be supplemented with heat, which we have assumed to be 10% of the heating requirements from a Mediuim Efficiency furnace. (Miller, 2008)

The results show that in Alberta, a Ground Source Heat Pump will result in greater GHG emissions than a High Efficiency conventional gas forced air furnance and only slightly lower GHG emissions than a Medium Efficiency conventional gas forced air furnace. The reason that the GHG emissions are high from the Ground Source Heat Pump is because in Alberta electricity is supplied by a high proportion of coal-fired power plants, which results in high electric grid carbon intensity. Another potential reason for high carbon intensities for ground source heat pumps in Alberta is due to low air conditioning use. In other locations, which have greater air conditioning demand in the summer, heat pumps offer a more efficient way to cool spaces than conventional air conditioning units that exchange heat with the air instead of with the cooler ground.

Table 5.32
Evaluation of GHG Impact of Replacing Conventional Furnace with Geothermal Heat Pump

		Medium Efficiency Residential Furnace	High Efficiency Residential Furnace	Ground Source Heat Pump		
				GSHP	Supplemental Heat: 10% of Medium Efficiency Furnace	Total
Energy Consumption						
Natural Gas	GJ/yr	130	111	0	13	13
Electricity	kWh/yr	920	650	9,000	92	9,092
Total	GJ/yr	133	113	32	13	46
GHG Emissions						
Natural Gas	g CO_2e/MJ	62.8	62.8	62.8	62.8	62.8
Electricity	g CO_2e/kwh	880	880	880	880	880
Total	$MTCO_2$e/yr	9.0	7.5	7.9	0.9	8.8

If all homes in Alberta were switched from conventional furnaces to Ground Source Heat Pumps, there could be as much as a 5% reduction in Alberta natural gas consumption. However, this switch could result in a 10% increase in Alberta electricity demand.

Technology Developments in Geothermal Heat Recovery

Incremental Improvement— We conclude that significant geothermal energy recovery from deep reservoirs is not likely in the time frame of the Study. However, technology advancements from oil production, especially drilling, will lead to lower cost for future geothermal energy recovery. In addition, greater experience with heat recovery from moderate to low-level sources will lead to lower cost geothermal sources of electricity.

We do not expect to see significant electricity generation from other sources of low level heat, such as oil production or process units in refineries, upgraders or other industries where energy efficiency and GHG reduction are part of normal business practices.

Increased demand for ground-source-based heating and cooling may occur if cooling demand increases and if the price for electricity relative to natural gas drops. Future developments may use ground source systems at remote locations in conjunction with solar energy recovery.

Breakthrough Technology— Unfortunately, the subsurface geology of Alberta (fairly low temperatures even at great depth) and the laws of thermodynamics (ultimate efficiency of heat engines) place significant boundaries on the ultimate potential of geothermal technology in the Province.

Biomass

Biomass is available in various forms in Alberta:

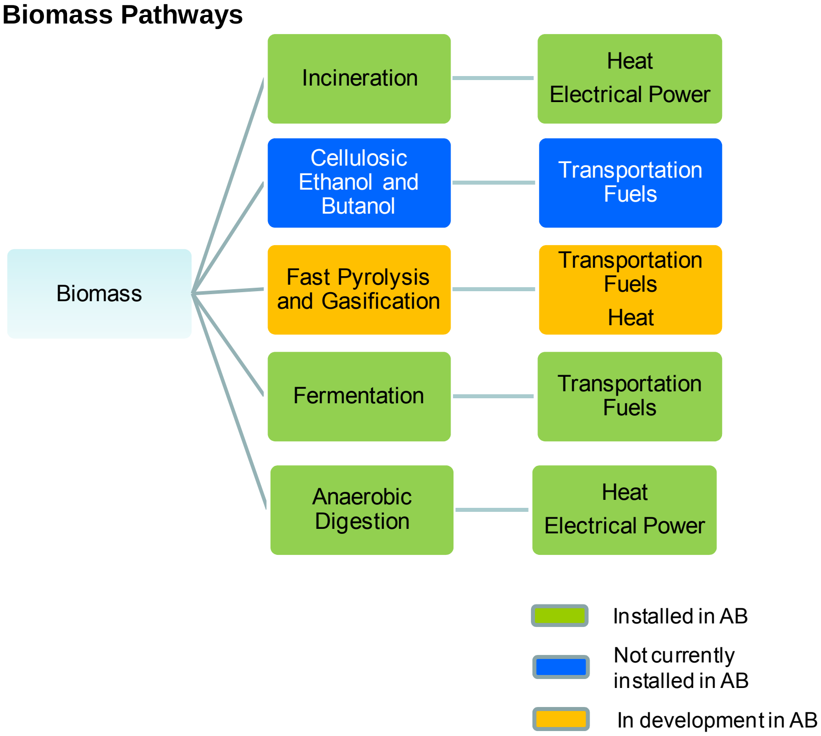
- Crops – wheat, barley, tame (also called cultivated) hay etc.
- Agricultural waste - The largest volume agricultural residue material in Alberta is field straw left over from wheat, barley, and oat production. Most of this residue is not used. It is left in the field to decay. Our estimation of amounts available assumes that an appropriate amount will be left in the field to ensure the maintenance of adequate soil structure and performance. It also takes into account the losses involved in various unit operations responsible for getting the straw from the field to a conversion plant and average efficiencies of different type of harvest and logistics equipment
- Forest residue - can be categorized into the following two classes:

- o Roadside Residues: These are also called forest harvest residues. These are the limbs and tops from the side of the logging road. They are what is left over after the logger removes the trunk (or stem) from the forest. The current practice in Alberta involves forwarding and piling of these residues and subsequent burning of these to prevent forest fires.
- o Mill Residues: These are sawdust, bark, and shavings from pulpmill and sawmill operations.

- Woody or whole forest biomass - refers to the trees from the forest which are cut and chipped. In this study we assumed all the trees are chipped (versus being used for lumber) and then transported to the conversion plant. We used the Province of Alberta Annual Allowable Cut (AAC) amounts as the basis for estimating available volume.

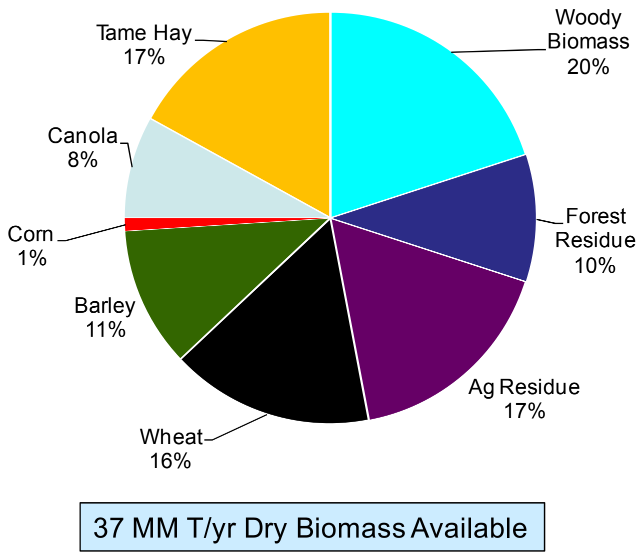
These resources can be used in a number of ways to provide energy commodities as shown in Figure 5.68. Incineration, fermentation (first generation ethanol production), and anaerobic digestion currently are in commercial use. The potential for technologies that are in development and have not been used commercially, such as cellulosic technologies and pyrolysis and gasification, will be addressed in the Technology Development section.

Figure 5.68
Biomass Pathways



An estimate of current annual biomass availability is shown in Figure 5.69.

Figure 5.69
Annual Biomass Production in Alberta

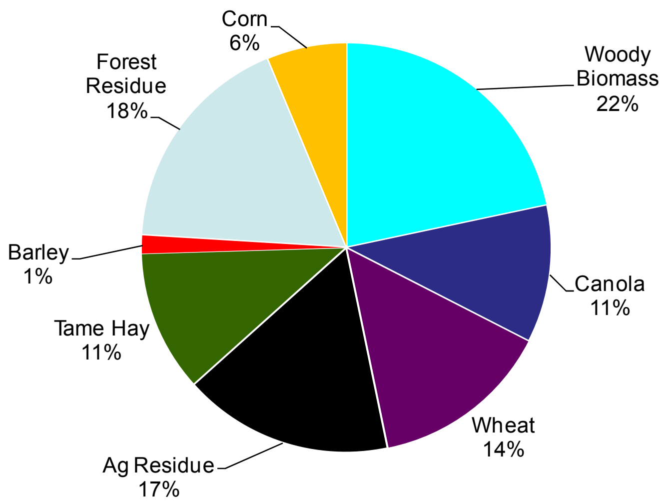


(JacobsConsultancy, University of Alberta, 2013)

Biomass – Total Energy Available

The total energy potentially available from the biomass sources in Figure 5.69 is shown in Figure 5.70.

Figure 5.70
Total Energy Available from Biomass in Alberta



700 PJ / yr
based on heat content

(JacobsConsultancy, University of Alberta, 2013)

Biomass to Transportation Fuels

In Alberta today, there is one facility that makes biofuels, a bioethanol-from-wheat facility. There are a number of new plants that have been announced but not yet started up as shown in Table 5.33.

Table 5.33
Installed and Announced Capacity Biomass to Transportation Fuels

Plant	Location	Capacity (MM liters / year)	Feedstock	Product	Status / Startup date
Permolex	Red Deer	45	Wheat,	Ethanol	Operating
Growing Power Hairy Hill	Vegreville	40	Wheat	Ethanol	Operating
Kyoto Fuels Corporation	Lethbridge	66	Multi-feedstocks	Biodiesel	Operating
Northern Biodiesel	Lloydminster	265	Canola	Biodiesel	Operating
Alpac	Boyle	5	Wood	Methanol	Operating
Western Biodiesel Inc	Calgary	19	Multifeedstocks	Biodiesel	Closed
FAME Biorefinery	Airdire	1	Canola, Carmelina, Mustard	Biodiesel	Demo Unit, switched to cooking oil production
Enerkem	Edmonton	35	MSW	Methanol / Ethanol	Under Construction
Hinton Pulp	Hinton		Tall Oil	Biodiesel	Proposed
BFuel	Lethbridge	68	Canola	Biodiesel	Proposed
Blue Horizon	Red Deer	30	Cellulosic Feedstocks	Biodiesel	Proposed
Mascoma	Drayton Valley	100-300	Cellulosic Feedstocks	Ethanol	Proposed

Biomass Conversion to Transportation Fuels

Commercially, biomass typically is converted to transportation fuels via two pathways; fermentation of starch-containing crops to ethanol or processing of bio-oils to biodiesel via trans-esterification. We have focused on wheat, barley, oats and canola as feedstocks.

Bioethanol from Wheat, Barley, Oats

The production of ethanol from wheat, barley and oats requires mechanical and enzymatic treatment to free the starch in the biomass and to convert the starch to sugar for fermentation.

Once the sugar has fermented, the resultant ethanol must be purified. The conversion of grain to ethanol begins with grain harvest via conventional farming techniques. Then the production pathway has the following steps:

- Milling and enzymatic treatment – The grain is ground into a meal which is slurried with water to form a mash. Enzymes are added to the mash to convert the starch in the mash to sugars. Enzymes also act to help control viscosity and control foaming of the mash.
- Fermentation – The mash is cooled and yeast is added to convert the sugar to ethanol and CO2. The ethanol produced via fermentation is approximately 10 - 12% ethanol in solution.
- Distillation and Purification – The ethanol is separated from the "stillage" and then the resulting dilute ethanol is distilled to bring the ethanol to 95 % concentration and then purified using molecular sieves to bring it to 99.7% concentration. Denaturant, typically light hydrocarbon, is added to the ethanol.
- Solids Treatment – The stillage is sent to a centrifuge to separate coarse grain from solubles. The solubles are concentrated to about 30% solids by evaporation to make Condensed Distillers Solubles (CDS). The CDS and the coarse grain are then dried together to make dried distillers grains with solubles (DDGS) which can be sold as livestock feed. Typically 100 kg of wheat produces approximately 29 kg ethanol along with 33 kg DDGS.

Some producers use a process in which the bran and gluten are separated from the grain at the beginning of the process before the enzymes are added. The rest of the process is essentially the same as the process outlined above.

In our analysis, water use and GHG emissions are based on wheat as a feedstock.

Water use is estimated by considering both direct and indirect consumption of water, i.e. water that is used directly for crop irrigation and for ethanol production, as well as water that is used in the production of fertilizers, chemicals and fuel. It includes water that is used for agricultural production and for conversion to biofuels. Water use associated with the transportation of the biomass to the conversion facility is not included as it is a relatively small value. Water use in the crop stage has been allocated to the grain and to the crop residues based on an assumption of 1:1.1 dry weight ratio of grain to wheat stalk. Water input for conversion is calculated based on the total production of ethanol + DDGS. If the water use was allocated separately to ethanol and DDGS, then the calculated water use would decline. Water usage includes both water that is consumed from natural sources (i.e. rainfall) and from irrigation and water supplied as process water.

GHG emissions calculations assume that waste biomass associated with the process (e.g. wheat straw or DDGS) is not used to provide energy for the process plant. A natural gas boiler and grid-supplied electricity are used to provide energy for the process plant. GHG emissions are associated with the production of bioethanol and not apportioned to DDGS production.

References cited include: (Crop Energies) (Vivergo, 2014) (Biokemi, 2007) (GEW Westfalia, 2010) (Singh S. K., 2011) (Low Carbon Vehicle Partnership, 2004).

Biodiesel from Canola

The majority of the biodiesel produced today is by means of a base-catalysed trans-esterification reaction. A fat or oil is reacted with an alcohol, like methanol, in the presence of a catalyst to produce glycerol and biodiesel (methyl esters). The methanol is charged in excess to assist in quick conversion and recovered for reuse. The catalyst is typically a strong base such as sodium hydroxide. The reaction typically takes place at low temperatures and pressures and has a high conversion with minimal side reactions and short reaction time. High free fatty acid oils require pre-treatment as the free fatty acids will create soaps in the process.

Typical production steps are:

- Canola seed crushing and oil extraction. Canola meal is produced in this step as a by-product of oil production.
- Feed filtration and degumming
- Free Fatty Acid Removal – the method is dependent on free fatty acid content, in this case it is assumed that it is treated with caustic soda and water
- Reaction - Base catalysed reaction of the low FFA oil with excess methanol
- Separation and methanol recovery with the methanol recycled to the catalysis step

Water use in the process is calculated as the water in canola seed production and crushing, feedstock preparation and in the methyl ester purification stage. Indirect water requirements are included in the water use estimate. Water usage includes both water that is consumed from natural sources (i.e. rainfall) and from irrigation and water supplied as process water.

GHG emissions are also calculated based on direct and indirect emissions and include agricultural production, nitrogen associated with fertilizer use, oil seed processing, trans-esterification and purification and use in a diesel engine. Energy use is adjusted to credit glycerol and oil mass share. The GHG emissions model referenced assumes that 2.34 kg of canola produce 1 kg of canola oil. In addition, the model allocates 42.8 % of the emissions from agricultural production, transportation and production to biodiesel and the balance to the canola meal. N_2O emissions from fertilizer use are approximately 30% of the total GHG emissions. References cited include: (National Biodiesel Board, 2014) (Van Gerpen, 2005) (Singh S. K., 2011) (California Air Resources Board, 2010)

Table 5.34 shows the output of traditional yeast fermentation to make bioethanol and the output of fatty acid methyl ester (FAME) technology to make biodiesel. Only crops that can produce ethanol through traditional yeast fermentation or biodiesel through methyl ester technology are included in the analysis. Those crops that may be able to produce ethanol through cellulosic ethanol processing routes are not considered since this route is not yet commercially proven. This analysis assumes all the crops currently produced in Alberta for these types of crops (i.e. wheat, canola etc.) are converted to biofuels. The amount of biofuels that could be produced corresponds to about 40% of gas and diesel consumption.

The heating value of ethanol is 21.3 MJ/l versus 32.4 MJ for typical gasoline without ethanol. Thus a liter of gasoline with 5 vol% ethanol will contain 1.7% less energy than a liter of gasoline without ethanol.

The heating value of FAME is 33.3 MJ/l versus 36.1 MJ/l for typical diesel without FAME. Thus a liter of diesel containing 2 vol% FAME will contain 0.2% less energy than a liter of diesel without FAME.

Table 5.34
Liquid Fuel Production from Alberta Biomass

Available Biomass Type	Product	Yield (liter product/ MT dry Biomass)	Liquid Fuel Product Energy * (PJ/year)
Wheat (Winter, Spring and Durham)	Ethanol	480	60
Barley	Ethanol	300	26
Corn	Ethanol	510	6
Canola (rapeseed)	Biodiesel	1100	110
Total			200

* Liquid Fuel Product Energy calculation assumes all biomass from each source (e.g. wheat, barley, corn etc) is converted to liquids fuels using existing commercial technology

Biofuels Technology Improvements

Incremental Improvement— Efforts to improve traditional fermentation and esterification technologies are focused on higher crop yields, energy efficiency, better utilization of by-products, reduced water consumption, lower susceptibility to salt, and greater pest resistance. .

Breakthrough Technology—

There are numerous technologies under development for the production of biofuels from biomass. Figure 5.71 and Table 5.35 show some of these routes and an estimate of total potential fuels that might be produced. Many of these technologies would enable the use of cellulosic and or non-food crops. The use of new crops potentially could lead to the conversion of marginal land to cropland.

Figure 5.71
Pathways under Development for Biomass

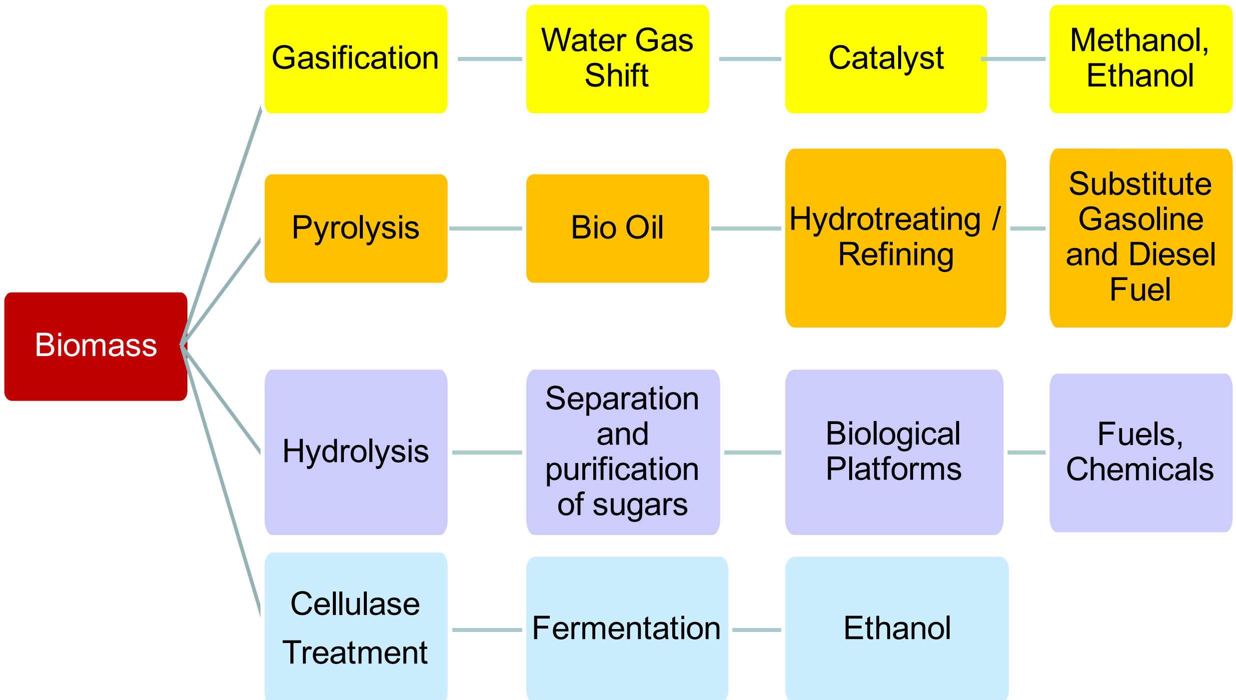


Table 5.35
Developing Routes for Bio Fuels: Potential Fuel Production Pathways

Process	**Gasification + Catalysis**	**Pyrolysis +co-Hydrogenation**	**Thermochemical processing + fermentation**	**Cellulosic Ethanol**
Product	**Ethanol**	**Substitute/ Drop in Gasoline and Distillate Blendstock**	**Diesel**	**Ethanol**
Available Biomass Type	Liquid Fuel Product Energy (Assumes total biomass use) (PJ/year)			
Woody Biomass (available, sustainable rate)	73	80	65	
Forest Residue (Woody Biomass Waste, available, sustainable rate)	37	40	33	
Agricultural Residue (Straw, available, sustainable rate)			43	43
Tame Hay				43
Total	110	120	140	86

Notes:

- Total Fuel production ranges from about 80 – 200 PJ depending on technology choice and biomass consumption. Biomass type can only be applied up to its maximum availability, thus total energy from all technologies is not additive.
- Assumes all of the available biomass type can be used to make fuel from a chosen particular process
- Pathways are not commercial technologies

The total fuel production from these developing routes is roughly 80 – 200 PJ depending on the combination of technology choices and which biomass type or types is consumed in each process. Table values reflect conversion of all available material for each biomass type via each process and thus are not additive. Maximum fuel production is equivalent to approximately 14 – 40% of Alberta's total transportation fuel demand.

Other potential improvements include smaller, more efficient plants to better match the crop gathering area or strategies to allow partial conversion at smaller plants with the final finishing steps at a centrally located plant.

Conversion of Biomass to Electricity and Heat

Wood Pellets

Currently in Alberta there are a number of plants creating wood pellets from bark and sawmill waste for use in biomass power production. About 90% of Canadian wood pellet production is exported for power generation and heat. Table 5.36 shows the existing mill capacity and the total energy potential if all Alberta forest residue were converted to pellets.

Table 5.36
Energy Content of Wood Pellets

	Existing Alberta Mill Capacity	**Total Forest Residue**
MT / year	120,000	3.7 MM
Annual Energy Content, PJ	2.2 – 2.5	69 – 78

(Wood Pellet Association of Canada, 2012 - 13),
(JacobsConsultancy, University of Alberta, 2013)

Federal GHG legislation requires coal- fired power plants to meet emissions standards for GHG emissions. Co-firing coal with wood pellets can reduce GHG emissions of the plants since the pellets are considered to have no contribution to the plant emissions. Figure 5.72 shows the feed rate of coal or wood pellets necessary to fire a 600 MW electrical power plant. The GHG contribution for each type of fuel is shown above the bar and are based on zero net GHG emissions from firing wood pellets. Since coal has a higher energy content than biomass, more biomass must be fired to produce the same amount of electricity. The last bar in the figure shows the fuel mix necessary to co-fire the power plant to enable it to meet the new emission limits of 420 g CO_{2e} / kW-hr. Coal feed must be reduced by more than half to meet the GHG limit.

Figure 5.72
Fuel Firing and GHG Emissions 600 MW of Power

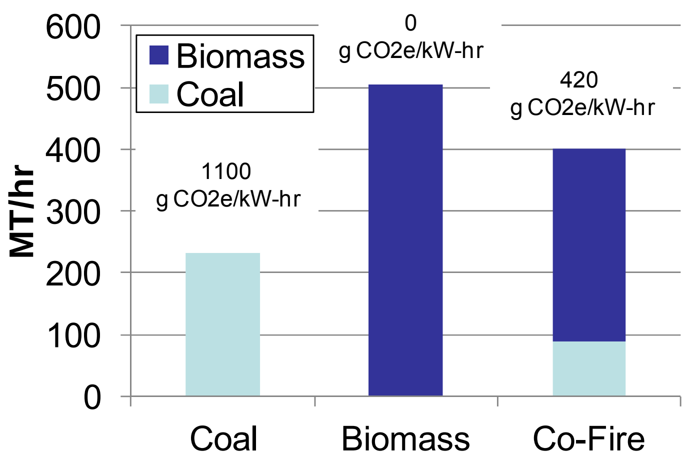


Table 5.37 shows the potential electrical power generating capacity based on existing pellet mill capacity and if all Alberta forest residue were used for electricity. The table also gives an estimate of generating capacity if the biomass were co-fired with coal.

Table 5.37
Scenarios for Generating Electricity from Wood Pellets

	Electric Power from Biomass, MW	Electric Power, Biomass co-fired with Coal, MW
Existing Pellet Mill Capacity	18	29
All Alberta Forest Residue	560	770

Alberta coal fired generating capacity in 2012 was 6,200 MW.

Black Liquor and Sawmill Waste

In addition to firing wood-pellets, biomass from other sources can be combusted to create heat and electrical power. Table 5.38 shows currently installed capacity for biomass to electricity in Alberta. Typically, these units are part of sawmills or pulp and paper mills. Black liquor boilers are used in pulp operations to provide steam and electricity to the pulp mill. The actual heat and electricity generated are not reported.

Table 5.38
Biomass to Electricity and Heat

Company	Fuel Source	Pathway	Capacity (MW)
Drayton Valley Power	Sawmill Residue	Combustion	12
Grande Prairie Ecopower Center	Sawmill Residue	Combustion	25
Whitecourt Biomass Generation Facility	Sawmill Residue	Combustion	28
Dapp Generating Station	Mill Residue, Harvest Residue, Demolition Wood	Gasification	17
Alberta Pacific Forest Industries	Black Liquor	Combustion	99
Daishowa Marubeni	Black Liquor	Combustion	50
Hinton Pulp Mill	Black Liquor	Combustion	50
Weyerhauser Canada	Black Liquor	Combustion	164
Total			445

Another pathway to electricity from biomass is by means of gasification. New capacity for Alberta has been announced, as shown in Table 5.39.

Table 5.39
Announced Capacity – Biomass Gasification to Electricity

Company	Location	Technology / Pathway	Energy Source	Capacity (MW)
Mustus Energy	La Crete	Gasification	Mill and harvest residues, deciduous roundwood	40.5
Mascoma	Drayton Valley	Gasification	Sawmill waste, waste lignin	17-52

Anaerobic Digestion

The anaerobic digestion of manure and other waste sludges produces biogas containing 50 - 75% methane. This gas can be treated and used as fuel for heating, as transportation fuel and to produce electricity. There are multiple small units in Alberta processing food by-products to generate heat and electricity. Table 5.40 shows announced and operating capacity. Figure 5.73 shows typical processing routes for anaerobic digestion.

Table 5.40
Announced Capacity – Anaerobic Digestion

Company	Location	Technology Type	Feedstock	Status	Capacity (kw)
Highmark Renewables	Two Hills	Vertical - Wet	manure & food processing waste, source separated organics	Operating	1000
Highmark Renewables	Two Hills	Vertical - Wet	manure & food processing waste, source separated organics	Operating	1000
Cargill Meat Solutions	High River	Lagoon - Wet	beef renderings	Operating	heat
Lamb Weston	Taber	Lagoon - Wet	potato renderings	Operating	heat
McCain Foods	Coaldale	Lagoon - Wet	Waste water	Operating	heat
Enmax	Calgary		Waste water	Operating	4600
City of Lethbridge	Lethbridge	Vertical - Wet	Waste water	Operating	1500
Epcor- Goldbar	Edmonton		Waste water	Operating	? 5000

Company	Location	Technology Type	Feedstock	Status	Capacity (kw)
Lethbridge Biogas	Lethbridge	Vertical - Wet	Food processes or waste, manure, SRM	Operating	2850
Capital Power Cloverbar	Edmonton	Landfill gas recovery	Landfill gas	Operating	4800
East Calgary landfill	Calgary	Landfill gas recovery	Landfill gas	Operating	70
Shepard landfill	Calgary	Landfill gas recovery	Landfill gas	Operating	400
Iron Creek Hutterite Colony	Bruce	Vertical - Wet	manure	Not Operating	375
Peace Pork	Falher	Vertical - Wet	manure	Not Operating	500
Miltow Colony	Warner	Covered earthen storage	manure	Not Operating	heat
Elm Spring Colony	Warner	Covered earthen storage	manure	May not be operating	flaring
GrowTEC	Chin	Vertical - Wet	potato waste	Partly built-under construction	633
Kingdom Farms	Bentley	Vertical - Wet	manure	proposed - partly built	2000
Biorefinex	Lacombe	Vertical - Wet	manure -SRM	Proposed - partly funded	1400
West Fraser Mills	Slave Lake		Pulp sludge	Under construction	7000
Millar Western	Whitecourt	anaerobic hybrid digesters	Pulp sludge	Under construction	5200
Landfill gas	Grand Prairie	Landfill gas recovery	Landfill gas	Under construction	1400
Optimal Biocell	Calgary	Landfill gas recovery	organic waste	Proposed - partly funded	
Edmonton Waste Management Centre	Edmonton	Vertical - Dry	organic waste	Proposed - partly funded	

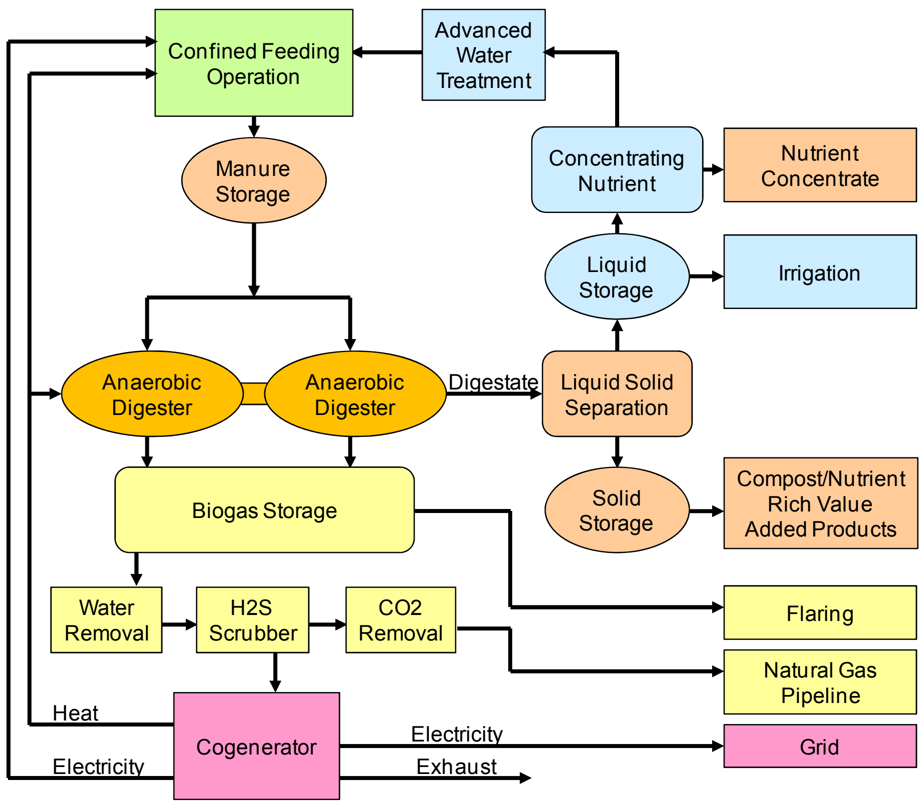
(Canadian Pork Council, 2006) " (Energy, 2013) (Bell, 2014)

In addition to generating power and fuels, projects may be implemented for other target benefits such as:

- Odor reduction
- Improving manure management systems by reducing pathogens and waste volume

- For pulp sludge, reducing need for polymer for dewatering and volume of sludge for disposal by incineration or landfill
- Reduction in organic matter loading for aerobic wastewater management systems for pulp operations or municipal wastewater treatment

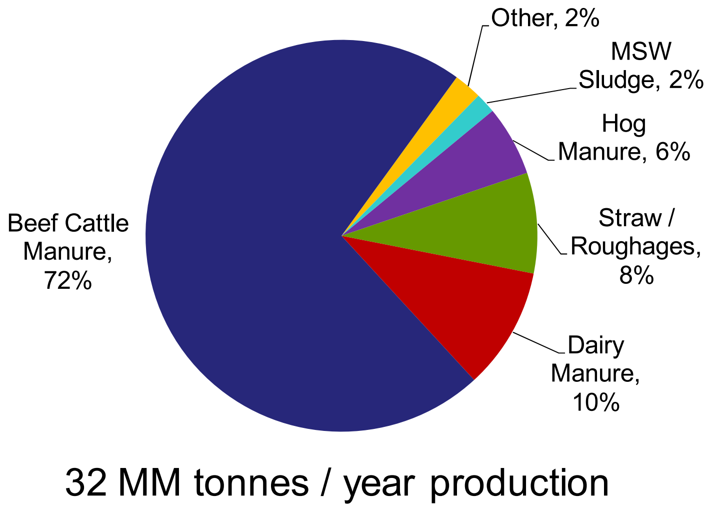
Figure 5.73
Pathways for Gas from Anaerobic Digestion



(Alberta Department of Agriculture, 2008)

In our estimate of available energy, we have considered that all manure in Alberta is available for anaerobic digestion and that all of the biogas is converted to electricity. In reality, not all manure is collected or can be collected, therefore only a portion of the manure would be available. In addition many operations would use the biogas to make heat and power or could potentially treat the gas and use it as a transportation fuel. Figure 5.74 shows a breakdown of Alberta manure production.

Figure 5.74
Manure Production in Alberta



(Alberta Department of Agriculture and Rural Development, 2008)

The available power from anaerobic digestion is calculated as:

> Power = Collection efficiency X Biogas emitted by the digestor X Heat content of gas X turbine/engine efficiency

Collection efficiencies are approximately 90%. The heat content is determined by the methane content of the gas which is typically 50 – 70%. The type of turbine or engine used in the facility is determined by the size of facility and the efficiencies range from 20 – 40% efficiency to electrical power. Table 5.41 provides a first-order estimate of energy available from anaerobic digestion.

Table 5.41
Anaerobic Digestion to Heat and Power

Anaerobic Digestion	
Million tonnes sludge available per year	32
Energy density of biogas, MJ/kg	16 - 20
Total Available Energy, PJ	20 - 40

(Alberta Department of Agriculture and Rural Development, 2011)

This amount of available energy represents approximately 10% of total Alberta energy demand and potentially could replace 7 - 22% of Alberta gas demand with biogas from anaerobic digestion.

Energy Pathways for Biomass to Transportation Fuels, Electricity and Heat

Table 5.42 demonstrates the efficiencies associated with converting 10,000 GJ.hr of biomass to the commodities of transportation fuels, electricity and heat.

Table 5.42
Energy Summary— Conversion of Biomass to Transportation Fuels, Electricity and Heat

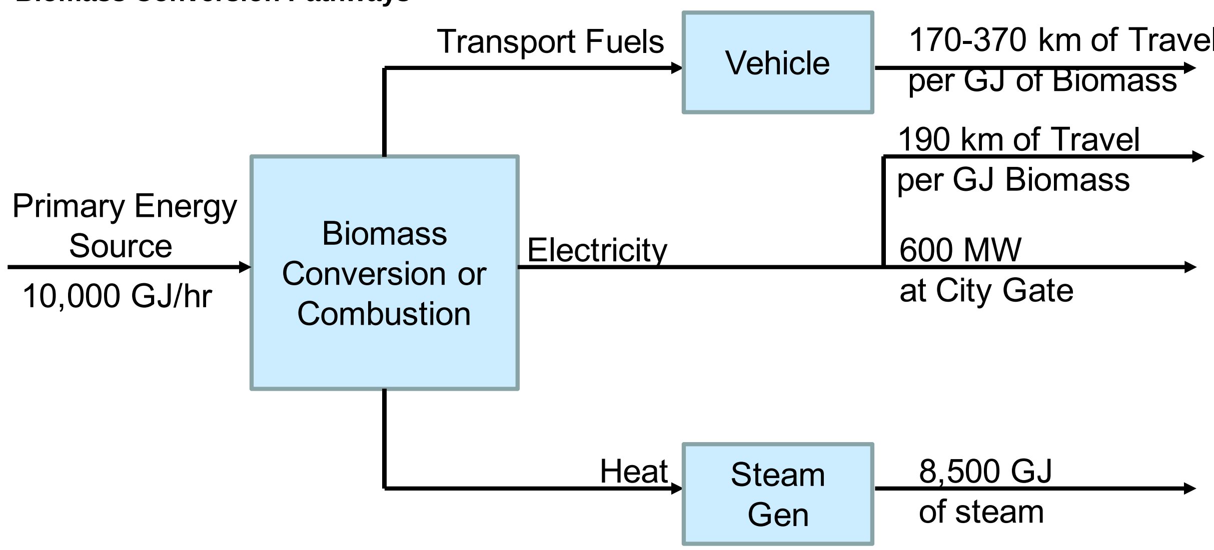
Biofuels Pathways	**Factors**	**Power, GJ/hr**
Fermentation to Ethanol		
Biomass Energy	Type of biomass, mass of biomass	10,000
Process Energy	Function of process chemistry and conditions, humidity level of biomass, includes energy for pesticide/herbicide use, gathering, conversion process, ethanol purification – estimated to be 95% of energy in biomass input	(9,500)
Power in Transportation Fuel Delivered		500

Biofuels Pathways	Factors	Power, GJ/hr
Canola to Biodiesel via FAME		
Biomass Energy	Type of biomass, mass of biomass	10,000
Process Energy	Function of process chemistry and conditions, humidity level of biomass, includes energy for pesticide/herbicide use, gathering, conversion process, biodiesel purification – 25% of energy in biomass input	(2,500)
Power in Transportation Fuel Delivered		7,500
Biofuel Combustion to Heat		
Biomass Energy	Type of biomass, mass of biomass	10,000
Feed Preparation	Function of biomass type, farming methods, gathering, biomass humidity level and biomass physical characteristics –estimated to be 30% of energy in the biomass	(3,000)
Efficiency losses	Boiler efficiency – estimated to be 85%	(1,000)
Heat Delivered		6,000
Biofuel Combustion to Electricity		
Biomass Energy	Type of biomass, mass of biomass	10,000
Feed Preparation	Function of biomass type, farming methods, gathering, biomass humidity level and biomass physical characteristics –estimated to be 30% of energy in the biomass	(3,000)
Efficiency losses	Boiler and generation efficiency – 85% boiler, 24% electrical production	(5,300)
Line losses	Function of grid characteristics, distance	(60)
Electrical power delivered		1,600

Biofuels Pathways	Factors	Power, GJ/hr
Anaerobic Digestion to Heat		
Biomass Energy	Type of biomass, mass of biomass	10,000
Gathering efficiency	Function of biomass type and humidity and design of gathering system – estimated to be 88%	(1,200)
Boiler efficiency	Function of boiler – estimated to be 95%	(60)
Heat delivered		8,700
Anaerobic Digestion to Electricity		
Biomass Energy	Type of biomass, mass of biomass	10,000
Gathering efficiency	Function of biomass type and humidity and design of gathering system – estimated to be 88%	(1,200)
Generation efficiency	Function of boiler and turbine/generator – estimated to be 21 – 34 % efficient	(6,400)
Line losses	Function of grid characteristics and distance	(80)
Electricity delivered to grid		2,300

Figure 5.75 outlines the pathways for biomass as a primary energy source converted to commodity transportation fuels, electricity and heat.

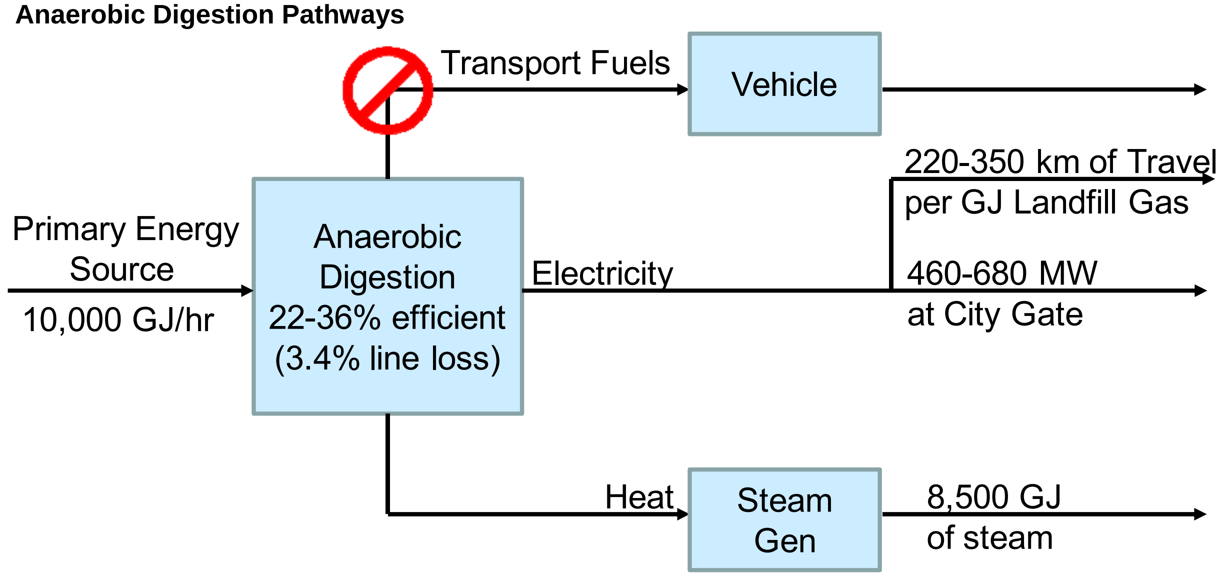
Figure 5.75
Biomass Conversion Pathways



Energy Pathways — Anaerobic Digestion

Figure 5.76 summarizes the pathways for anaerobic digestion of manures to commodity electricity and heat.

Figure 5.76
Anaerobic Digestion Pathways



Biomass metrics are summarized in Table 5.43

Table 5.43
Biomass Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Biomass to Ethanol	Biomass to Biodiesel	Biomass Combustion	Anaerobic Digestion
Energy Type							
	Type of Source			Stock / Flow	Stock / Flow	Stock / Flow	Stock / Flow
Production and Capacity							
	Remaining Established Reserve Potential, Primary Source	PJ		not applicable	not applicable	not applicable	not applicable
	Annual Production of Energy from Primary Source						
	Actual Annual Production, Primary Source	PJ/yr		280	120	700	20 - 40
	Biomass, MSW, Landfill Gas	MT		17,000	2,800	37,000	32,000
	Available Commodity Production Capacity (Current Installed Capacity)						
	Commodity - Conventional Units						
	Transportation Fuels	MM Bbls/yr		0.53			
	Electricity	MW				350	3
	Commodity - PJ/yr						
	Transportation Fuels	PJ/yr		0.1			
	Electricity	PJ/yr				11.0	0.1
	Current actual commodity produced						
	Commodity - Conventional Units						
	Transportation Fuels	MM Bbls/yr	86	Not Available			
	Electricity	GWh/yr	75,500			Not Available	Not Available
	Heat	PJ/yr	1,260				
	Commodity - PJ/yr						
	Transportation Fuels	PJ/yr	468				
	Electricity	PJ/yr	272			Not Available	Not Available
	Heat	PJ/yr	1,260				
	Transportation Fuels	%		Not Available			
	Electricity	%				Not Available	Not Available
	Commodity Production if all Alberta Primary Source is Converted to Commodity						
	Commodity - Conventional Units						
	Transportation Fuels	MM Bbls/yr		40	20		
	Electricity	GWh/yr				29,000	7,000.0
	Heat	PJ/yr				420	22.3
	Commodity - PJ/yr						
	Transportation Fuels	PJ/yr		140	100		
	Electricity	PJ/yr				100	6.954
	Heat	PJ/yr				420	22
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption						
	Transportation Fuels	%		47	42		
	Electricity	%				38	3
	Heat	%				29	2

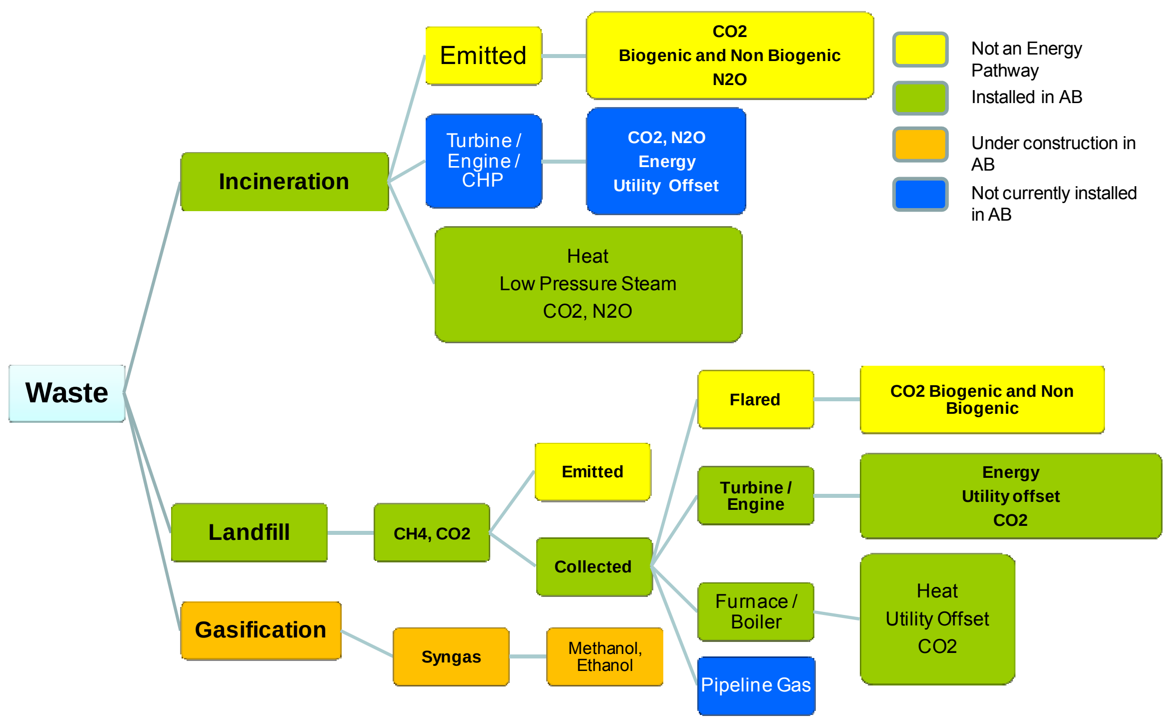
Table 5.43 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Biomass to Ethanol	Biomass to Biodiesel	Biomass Combustion	Anaerobic Digestion
Energy Density of Energy Source							
	Primary Source (HHV)	MJ/kg		18.0	41.6	15 - 19	16 - 21
	Transportation Fuel - weighted average	MJ/kg		26.9	38.3		
Efficiency and Energy Consumption							
	Energy Consumption						
	Transportation Fuels	GJ/GJ		0.95	0.25		
	Electricity	GJ/GJ				5.79	0.84
	Heat	GJ/GJ				0.69	0.25
	Net Energy Ratio						
	Transportation Fuels	GJ/GJ		0.33	0.75		
	Electricity	GJ/GJ				0.08	.16 - .27
	Heat	GJ/GJ				0.42	0.74
	Electricity Conversion						
	Efficiency of power plant conversion	%				23.70	22 - 36
	Electricity	kW-hr/GJ Primary Source				41	45 - 75
	Distance Delivered						
	Distance delivered from Electricity	km/GJ Primary Source				194	220 - 350
	Distance delivered from Transportation Fuels	km/GJ Primary Source		170	370	not applicable	not applicable
Environmental Metrics							
	GHG						
	Transportation Fuels	g CO2e/MJ		100	32.0		
	Electricity	g CO2e/MJ				Assume -0	Assume -0
	Heat	g CO2e/MJ				Assume -0	Assume -0
	Land Use						
	Transportation Fuels	ha/PJ		40 - 50	20		
	Electricity	ha/PJ				0.088	
	Heat	ha/PJ				0.022	
	Water Use						
	Transportation Fuels	m3/GJ		51.600	124.00		
	Electricity	m3/GJ				0.8	6.591
	Heat	m3/GJ				0.1896	2.024
	Air emissions						
	Transportation Fuels	g/MJ		not available	not available		
	Electricity	g/MJ				not available	not available
	Heat	g/MJ				not available	not available
	Solids emissions						
	Transportation Fuels	g/MJ		not available	not available		
	Electricity	g/MJ				not available	not available
	Heat	g/MJ				not available	not available

Landfill / MSW

Alberta generates four million metric tonnes of municipal solid waste (MSW) per year (Statistics Canada). The Province currently operates a number of landfill gas collection sites with electricity generation from the landfill site. In addition, there is one waste incinerator that provides heat to a nearby seed processing facility. Currently under development is an MSW to syngas unit near Edmonton being built by Enerkem. Figure 5.77 depicts routes for conversion of the organic content of waste to commodity energy products.

Figure 5.77
Pathways for Landfill Material



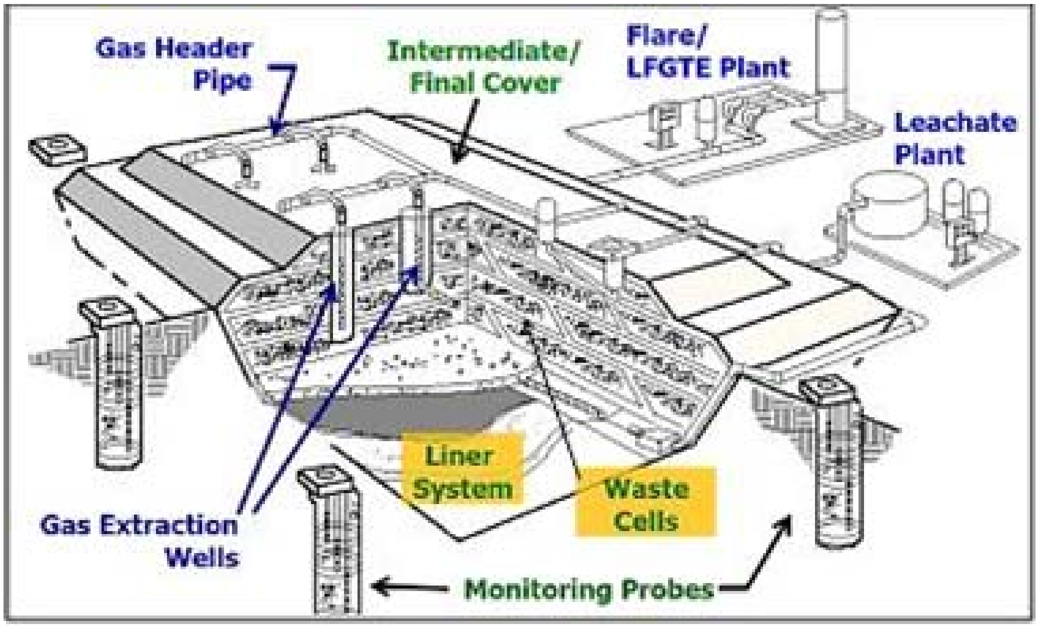
Landfill Gas to Energy

There are two locations in Alberta where landfill gas is recovered to generate electricity:

- West Clover Landfill, Edmonton with 3 x 1.6 MW internal combustion (IC) engines
- Shepard Landfill, Calgary with a 0.38 MW microturbine

As shown in Figure 5.78, these systems gather the landfill gas that is generated in the landfill and use the gas to create energy. The gas is approximately 50% methane and 50% CO_2. The methane content of the gas is affected by the age of landfill, humidity, organic content, and ambient temperature.

Figure 5.78
Typical Landfill Gas to Energy Configuration



In addition to generating energy, landfill gas systems reduce GHG emissions by capturing the methane emissions from the landfill. In many cases, landfill operators will gather the gas and flare it if the landfill is not large enough to warrant a generating system (CO_2 has a lower global warming potential than methane emitted to the atmosphere).

The available power from a landfill gas system may be calculated as:

Power = Collection efficiency X Biogas / Landfill gas emission rate X Heat content of gas X turbine/engine efficiency

Table 5.44 shows typical efficiencies for landfill gas systems.

Table 5.44
Available Energy – Landfill Gas

Technology Choice	Efficiency	Typical Throughput (50 % methane)	Size	Comment
Turbine	5 - 30%	Greater than 1300 cfm	3 – 5 MW	Less efficient at low throughput, requires high throughput
Internal Combustion Engine	22 – 36%	300 – 1100 cfm	0.8 – 3 MW	Flexible, most often used in landfill gas applications
Microturbine	22 – 30%	20 -200 cfm	30 – 250 kW	Low methane content, low flow

(EPA Combined Heat and Power Partnership, 2007), (EPA Landfill Methane Outreach Program)

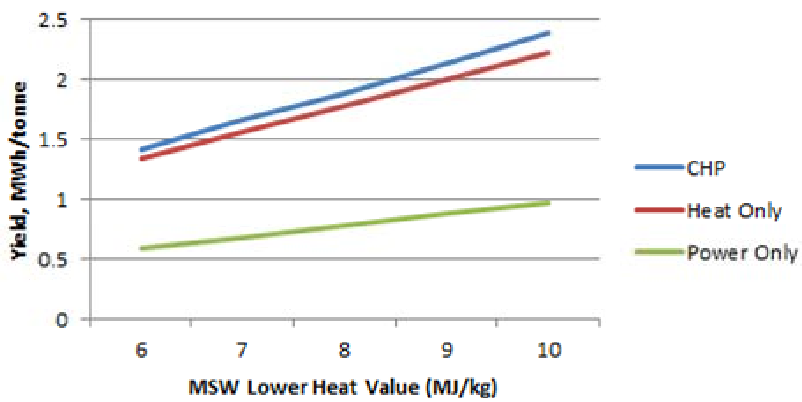
The total landfill gas in Alberta was modeled using a US government landfill gas model (EPA Air and Climate Change Research, 2005) based on the assumption that all the MSW in Alberta was placed in a single landfill that was 20 years old. We assumed that the landfill gas collection system had an efficiency of 88% and efficiency to electrical power of 34%. Based on these assumptions, landfill gas in Alberta potentially could generate 1,100 GWh/year or 1.5% of Alberta electricity demand.

MSW Incineration to Energy

The Wainright Regional WTE facility incinerates MSW to provide heat to a local seed drying factory. The unit was designed to process 29 tpd of waste (approximately 10,000 tpy) and produced 115 000 GJ in 2006 (Environment Canada, 2013). These units typically provide solid waste reduction of about 75%. The efficiency of the unit is dependent on the configuration of the unit (combined heat and power or simply heat or power) and the heat content of the waste source.

Units can be configured to produce both heat and power. Figure 5.79 shows a typical heat and power yield for MSW as a function of heat content. The calculation of energy potential for Alberta assumed that all MSW is incinerated in a unit that only produces electricity or produces only heat.

Figure 5.79
Energy Yield MSW Incineration



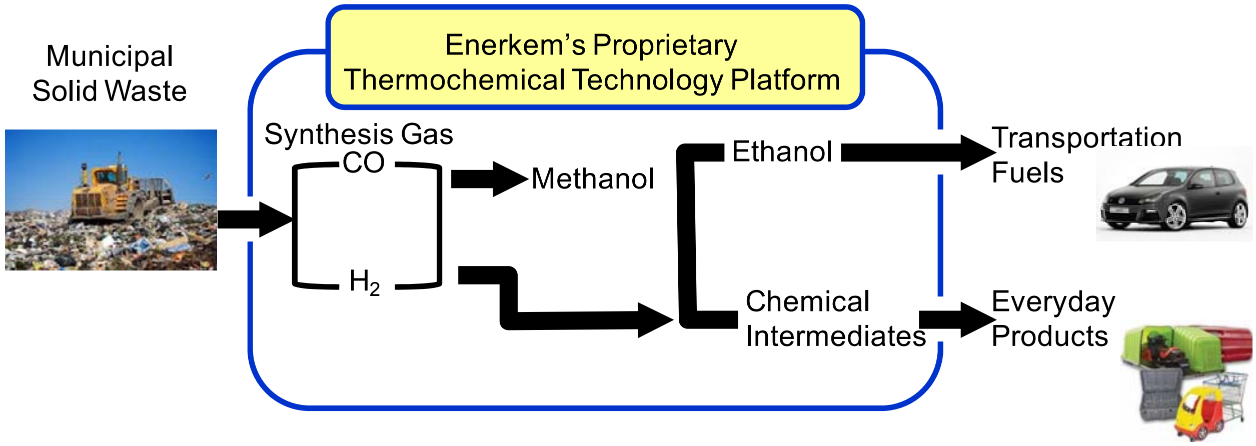
(World Bank, 1999)

Technology Improvements— MSW

Incremental Improvements— One of the bigger challenges for MSW is the separation of organic and inorganic waste. Efforts are underway to improve the efficiency of collection and sorting processes.

Breakthrough Technology— New technology is being implemented in Edmonton for the gasification of MSW to make syngas for the production of ethanol. The process is by Enerkem. Figure 5.80 shows the flow scheme for the concept. The technology aims to make low carbon intensity transportation fuels or chemicals from waste.

Figure 5.80
Enerkem MSW to Products Flow Scheme



Pathways Landfill Gas and MSW Combustion

Table 5.45 summarizes the efficiencies of converting 10,000 GJ/hr of landfill gas or MSW to electricity.

Table 5.45
Energy Summary— Conversion of Landfill Gas and MSW to Electricity

MSW Pathways	Factors	Power, GJ/hr
Landfill Gas to Electricity		
Landfill Gas Energy	Landfill contents (e.g. % of organics), age of landfill, landfill design	10,000
Gathering efficiency	Function of landfill contents, age and design of gathering system – 88% efficient	(1,200)
Generating efficiency	Function of type of turbine/generator	(6,600)
Line losses	Function of grid characteristics, distance	(80)
Electrical power delivered		2,100
Biofuel Combustion to Electricity		
Biomass Energy	Type of biomass, mass of biomass	10,000
Feed Preparation	Function of humidity level and biomass physical characteristics, energy inputs for transportation, drying and feed prep	(1,500)
Efficiency losses	Thermal losses from furnace, boiler efficiency, turbine efficiency, generator efficiency , electrical energy for plant operation	(6,600)
Line losses	Function of grid characteristics, distance	(90)
Electrical power delivered		1,800

Figure 5.81 shows the energy pathways for landfill gas and MSW combustion to electricity or heat.

Figure 5.81
Pathways for Landfill Gas and MSW

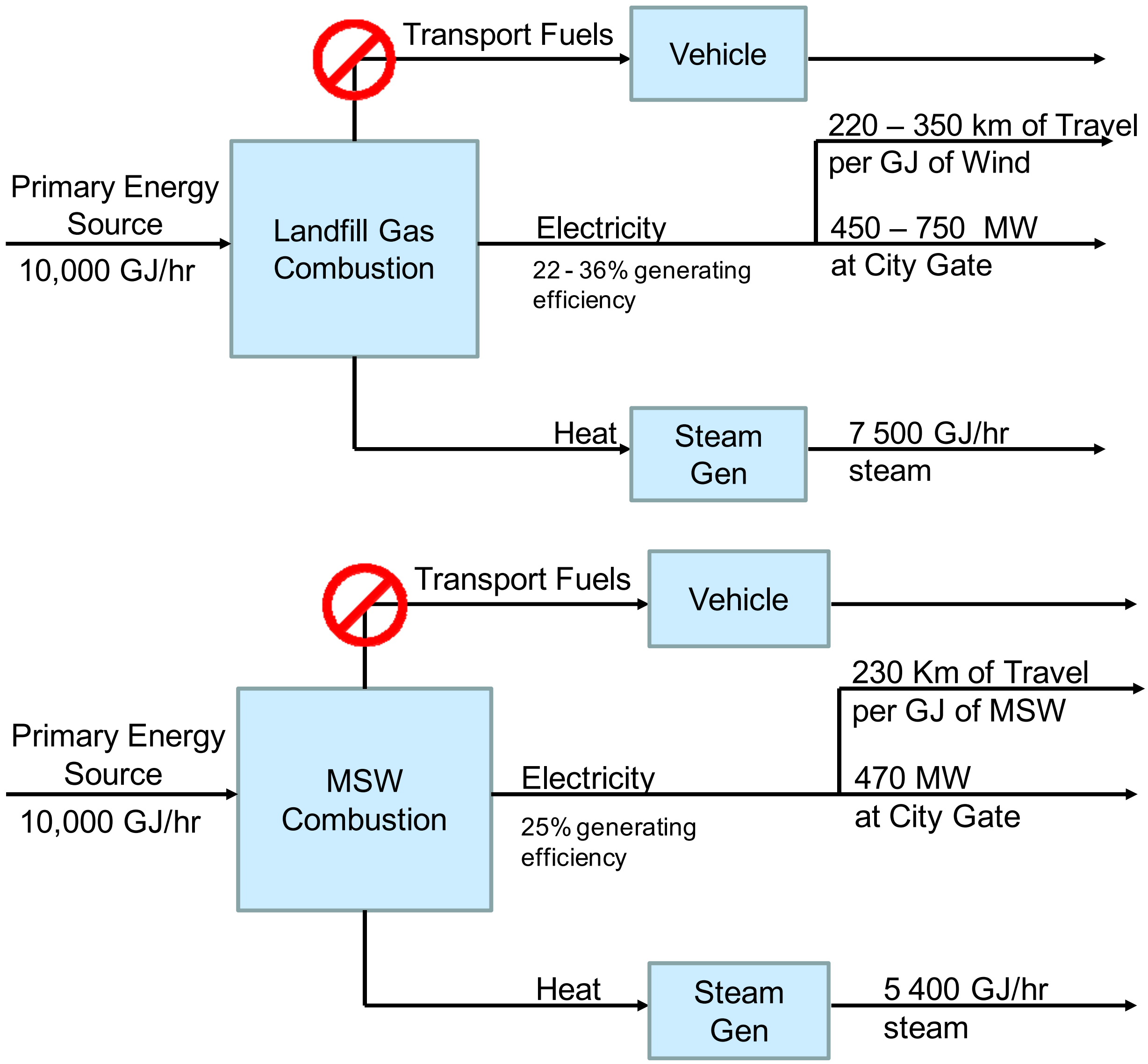


Table 5.46 summarizes the metrics for recovery of energy from landfill gas and municipal solid waste.

Table 5.46
Landfill Gas and MSW Metrics

Metric Type	Metric	Primary Source	Alberta Total Demand	Landfill	MSW
Energy Type					
	Type of Source			Stock / Flow	Flow
Production and Capacity					
	Remaining Established Reserve Potential, Primary Source	PJ		Not applicable	Not applicable
	Annual Production of Energy from Primary Source				
	Actual Annual Production, Primary Source	PJ/yr		13	62
	Biomass, MSW, Landfill Gas	MT		880,000	4,030,000
	Available Commodity Production Capacity (Current Installed Capacity)				
	Commodity - Conventional Units				
	Electricity	MW		5	
	Heat	PJ/yr			0.1
	Commodity - PJ/yr				
	Electricity	PJ/yr		0.2	
	Heat	PJ/yr			0.1
	Current actual commodity produced				
	Commodity - Conventional Units				
	Transportation Fuels	MM Bbls/yr	86		
	Electricity	GWh/yr	75,500	470	
	Heat	PJ/yr	1,260		0.1
	Commodity - PJ/yr				
	Transportation Fuels	PJ/yr	468		
	Electricity	PJ/yr	272	0	
	Heat	PJ/yr	1,260		0.1
	Electricity	%		0.0	
	Heat	%			0.01
	Commodity Production if all Alberta Primary Source is Converted to Commodity				
	Commodity - Conventional Units				
	Electricity	GWh/yr		800	3,000
	Heat	PJ/yr		10	32
	Commodity - PJ/yr				
	Electricity	PJ/yr		2.8	10.8
	Heat	PJ/yr		10	32
	Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption				
	Electricity	%		1	4
	Heat	%		1	3

Table 5.46 (cont)

Metric Type	Metric	Primary Source	Alberta Total Demand	Landfill	MSW
Energy Density of Energy Source					
	Primary Source (HHV)	MJ/kg		13	15
Efficiency and Energy Consumption					
	Energy Consumption				
	Electricity	GJ/GJ		2 - 5	4.71
	Heat	GJ/GJ		0.34	0.91
	Net Energy Ratio				
	Electricity	GJ/GJ		0.09	0.10
	Heat	GJ/GJ		0.6	0.4
	Electricity Conversion				
	Efficiency of power plant conversion	%		22 - 36 %	35
	Electricity	kW-hr/GJ Primary Source		46	49
	Distance Delivered				
	Distance delivered from Electricity	km/GJ Primary Source		220 - 350	230
Environmental Metrics					
	GHG				
	Electricity	g CO2e/MJ		Assume -0	Assume -0
	Heat	g CO2e/MJ		Assume -0	Assume -0
	Land Use				
	Water Use				
	Electricity	m3/GJ		0.43	0.43
	Heat	m3/GJ		0.12	0.15
	Air emissions				
	Electricity	g/MJ		0.035	0.01
	Heat	g/MJ		0.016	0.01
	Solids emissions				
	Electricity	g/MJ			-127
	Heat	g/MJ			-55

Section 6.

Comparison of Metrics

Comparison of Metrics

The metrics described in Section 4 can be used to compare the different energy sources and pathways to produce commodity energy products: transportation fuels, electricity, and heat. We evaluated each energy resource with the following metrics:

- Production and Capacity
  - Remaining established reserve potential, primary source
  - Annual production of energy from primary source
  - Available commodity production capacity (current installed capacity)
  - Current actual commodity produced
  - Available commodity % of Alberta consumption
  - Commodity production if all Alberta primary source is converted to commodity
  - Commodity production if all Alberta primary source is converted to commodity, % of Alberta consumption
- Energy density of energy source
- Efficiency and energy consumption
  - Energy consumption
  - Net energy ratio
  - Electricity conversion
  - Distance delivered
- Environmental Metrics
  - GHG
  - Land use
  - Water use
  - Air emissions
  - Solids emissions

Overall Metrics Tables

A summary of the overall metrics for all the energy sources is given in Table 6.1. An explanation of the assumptions and references in estimating each metric for each energy resource is in Table 6.2; explanations are identified by row number, energy resource, and metric. Table 6.3 explains the notes in the third column from the left in Table 6.1.

Table 6.1.
Energy Metrics Comparison – 1

Row	Master		Metrics Summary as of	26-Mar																				
5	Metric Type	Note	Metric	Primary Source	Alberta Total Demand	Coal	Conventional Crude	Bitumen Mined	Bitumen In Situ	Total Oil	Natural Gas	Nuclear	Hydro	Wind	Solar PV Distributed	Solar PV Utility	Solar Thermal	Geothermal	Biomass to Ethanol	Biomass to Biodiesel	Biomass Combustion	Anaerobic Digestion	Landfill	MSW
6	Energy Type																							
7			Type of Source			Stock	Stock	Stock	Stock	Stock	Stock	Stock	Flow	Flow	Flow	Flow	Flow	Stock/Flow	Stock / Flow	Stock / Flow	Stock / Flow	Stock / Flow	Stock / Flow	Flow
8	Production and Capacity																							
9		1	Remaining Established Reserve Potential, Primary Source	PJ		790,100	9,700.0	209,639	848,461	1,058,100.0	35,200	not available	not applicable	not applicable	Not applicable	Not applicable	Not applicable		not applicable	not applicable	not applicable	not applicable	Not applicable	Not applicable
10			Annual Production of Energy from Primary Source																					
11		2	Actual Annual Production, Primary Source	PJ/yr		598	1,270	2,140	2,281	5,691	3,936		not applicable	not applicable	Not available	Not applicable	Not available	nil	280	120	700	20 - 40	13	62
12			Oil and Bitumen	MM Bbls/yr			210	340	360	910														
13			Coal, Uranium	MM MT/yr		29																		
14			Natural Gas	Billion scfd							10													
15			Biomass, MSW, Landfill Gas	MT															17,000	2,800	37,000	32,000	880,000	4,030,000
16			Available Commodity Production Capacity (Current Installed Capacity)																					
17																								
18			Commodity - Conventional Units																					
19		3	Transportation Fuels	MM Bbls/yr						127									0.53					
20		4	Electricity	MW		6,249	nil	nil	nil	nil	5400		900	1,100	3.2	Not applicable		nil			350	3	5	
21			Heat	PJ/yr			nil	nil	nil	nil	1,237						Not available							0.1
22			Commodity - PJ/yr																					
23			Transportation Fuels	PJ/yr		Not Applicable				696									0.1					
24		5	Electricity	PJ/yr		200	nil	nil	nil	nil	170		28	35	Not available	Not applicable		nil			11.0	0.1	0.2	
25			Heat	PJ/yr			nil	nil	nil	nil	1,237						Not available							0.1
26			Current actual commodity produced																					
27			Commodity - Conventional Units																					
28			Transportation Fuels	MM Bbls/yr	86		not applicable	not applicable	Not applicable	127									Not Available					
29		6	Electricity	GWh/yr	75,500	37,800	nil	nil	nil	nil	26,700		2,200	3,000	Not available	Not applicable					Not Available	Not Available	470	
30			Heat	PJ/yr	1,260		nil	nil	nil	nil	1237						Not available							0.1
31			Commodity - PJ/yr																					
32			Transportation Fuels	PJ/yr	468					696														
33			Electricity	PJ/yr	272	136	nil	nil	nil	nil	96		8	11	Not available	Not applicable					Not Available	Not Available	0	
34			Heat	PJ/yr	1,260		nil	nil	nil	nil	1,237						Not available							0.1
35			Available Commodity % of Alberta Consumption																					
36		7	Transportation Fuels	%						148									Not Available					
37			Electricity	%		50	nil	nil	nil	nil	35		3	4	Not available	Not applicable		nil			Not Available	Not Available	0.0	
38			Heat	%			nil	nil	nil	nil	98						Not available	nil						0.01
39		8	Commodity Production if all Alberta Primary Source is Converted to Commodity																					
40			Commodity - Conventional Units																					
41			Transportation Fuels	MM Bbls/yr			190	320	350	860	780								40	20				
42			Electricity	GWh/yr		53,500	133,000	225,000	239,000	594,000	538,600		53,050	500,000	6,900	7,300,000		3,403,000			29,000	7,000.0	800	3,000
43			Heat	PJ/yr			1,080	1,820	1,940	4,840	3,346						3 -4				420	22.3	10	32
44			Commodity - PJ/yr																					
45			Transportation Fuels	PJ/yr			1,170	2,020	2,210	5,400	3,936								140	100				
46			Electricity	PJ/yr		192	480	810	860	2,140	1,939		191	1,800	25	26,000		12,250			100	6.954	2.8	10.8
47			Heat	PJ/yr		510	1,080	1,820	1,940	4,840	3346						3 -4				420	22	10	32
48			Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption																					
49			Transportation Fuels	%			149	252	275	677	566								47	42				
50			Electricity	%		71	177	298	317	788	714		70	700	9	9700		4510			38	3	1	4
51			Heat	%		40	86	144	154	384	266						3				29	2	1	3
52	Energy Density of Energy Source																							
53			Primary Source (LHV)	MJ/kg		20.9	44.4	39.2	39.2	40.3	47.1				Not applicable	Not applicable	Not applicable	Not Applicable						
54			Primary Source (HHV)	MJ/kg							52.2				Not applicable	Not applicable	Not applicable		18.0	41.6	15 - 19	16 - 21	13	15
55			Primary Source (LHV) - from ore	MJ/kg								3900			Not applicable	Not applicable	Not applicable							
56			Transportation Fuel - weighted average	MJ/kg											Not applicable	Not applicable	Not applicable		26.9	38.3				

Table 6.1 (cont)
Energy Metrics Comparison-2

Row	Master		Metrics Summary as of	26-Mar																				
5	Metric Type	Note	Metric	Primary Source	Alberta Total Demand	Coal	Conventional Crude	Bitumen Mined	Bitumen In Situ	Total Oil	Natural Gas	Nuclear	Hydro	Wind	Solar PV Distributed	Solar PV Utility	Solar Thermal	Geothermal	Biomass to Ethanol	Biomass to Biodiesel	Biomass Combustion	Anaerobic Digestion	Landfill	MSW
57	Efficiency and Energy Consumption																							
58		9	Energy Consumption																					
59			Transportation Fuels	GJ/GJ			0.25	0.41	0.41	0.37	0.1								0.95	0.25				
60		10	Electricity	GJ/GJ		1.84 - Existing Gen; 3.15 - New Gen with CCS	1.78	1.77	1.98	1.86	1.22	2.3	nil	not applicable	nil	nil					5.79	0.84	2 - 5	4.71
61			Heat	GJ/GJ		0.22	0.23	0.23	0.32	0.27	0.31						nil				0.69	0.25	0.34	0.91
62		11	Net Energy Ratio																					
63		12	Transportation Fuels	GJ/GJ			0.70	0.59	0.61	0.62	0.82							Not Applicable	0.33	0.75				
64			Electricity	GJ/GJ		0.21 - Existing Gen; 0.14 - New Gen with CCS	0.22	0.22	0.20	0.21	0.28	0.19	0.70	0.28	0.10	0.097		Not Applicable			0.08	.16 - .27	0.09	0.10
65			Heat	GJ/GJ		0.70	0.68	0.69	0.61	0.66	0.62						not available	Not Applicable			0.42	0.74	0.6	0.4
66			Electricity Conversion																					
67			Efficiency of power plant conversion	%		37.674 w/o CCS - current capacity; 26.082 for new capacity w CCS	39	39	39	39	51	33	70	34	10	10		15			23.70	22 - 36	22 - 36 %	35
68			Electricity	kW-hr/GJ Primary Source		105 kw-hr/GJ of Coal - Existing Capacity: 72 kw-hr/GJ of Coal - New capacity with CCS	105	105	105	104	123	57	188	80	28	27		39			41	45 - 75	46	49
69			Distance Delivered																					
70			Distance delivered from Electricity	km/GJ Primary Source		497 km/GJ of Coal - Existing Capacity: 341 km/GJ of Coal - New capacity with CCS	500	500	500	500	583	268	889	380	132	127		185			194	220 - 350	220 - 350	230
71			Distance delivered from Transportation Fuels	km/GJ Primary Source			310	280	300	290	307				not applicable	not applicable	not applicable		170	370	not applicable	not applicable		
72	Environmental Metrics																							
73		13	GHG																					
74			Transportation Fuels	g CO2e/MJ			89.7	102.8	100.5	99.0	64							Not Applicable	100	32.0				
75			Electricity	g CO2e/MJ		281	205	233	237	228	126	1.8 - 4.2	37	0.07	nil	nil		nil			Assume -0	Assume -0	Assume -0	Assume -0
76			Heat	g CO2e/MJ		120	91.0	103.0	105.0	101.0	76						nil	nil			Assume -0	Assume -0	Assume -0	Assume -0
77		14	Land Use																					
78			Transportation Fuels	ha/PJ			0.0033	0.0012	0.0003	0.0013	nil								40 - 50	20				
79			Electricity	ha/PJ		0.045	0.0080	0.0029	0.0008	0.0032	nil	0.9	5.3	0.00012	nil	750		nil			0.088			
80			Heat	ha/PJ		0.019	0.0036	0.0013	0.0004	0.0014	nil						nil	nil			0.022			
81			Water Use																					
82			Transportation Fuels	m3/GJ			0.005 - 0.22	0.10	0.008 -0.031	0.005-0.104	0.004								51.600	124.00				
83			Electricity	m3/GJ		0.58	0.37	0.37	0.37	0.37	0.27	0.52	6 -70	0.09	nil	nil		0.32			0.8	6.591	0.43	0.43
84			Heat	m3/GJ		0.205	0.005 - 0.22	0.10	0.008 -0.031	0.005-0.104	0.057						nil				0.1896	2.024	0.123485625	0.15
85			Air emissions																					
86			Transportation Fuels	g/MJ			Not available	Not available	Not available	Not available	nil							Not Available	not available	not available				
87			Electricity	g/MJ		5.7	Not available	Not available	Not available	Not available	nil	0.00	nil	nil	nil	nil		Not Available			not available	not available	0.035	0.01
88			Heat	g/MJ		2.4	Not available	Not available	Not available	Not available	nil						nil	Not Available			not available	not available	0.016	0.01
89			Solids emissions																					
90			Transportation Fuels	g/MJ			Not available	Not available	Not available	Not available	nil							Not Available	not available	not available				
91			Electricity	g/MJ		34.0	Not available	Not available	Not available	Not available	nil	13.1	nil	nil	nil	nil		Not Available			not available	not available		-127
92			Heat	g/MJ		15.0	Not available	Not available	Not available	Not available	nil						nil	Not Available			not available	not available		-55

Table 6.2.
Energy Metrics Comparison – Assumptions and Further Description-1

Row on Metrics Master	Originating Sheet	Tag	Note	Description
58	Metrics-Wind	Wind - Net Energy Ratio	7	Net Energy Ratio = Energy in the Commodity / (Energy to convert primary source to commodity + energy in the Primary Source), does not include the energy to build the conversion facility
62	Metrics-Wind	Wind - Land Use	9	Land density = land disturbed by the pathway process only. It does not include transmission line land use.
20	Metrics-Wind	Wind - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-MW	10	AESO 2012 1087 MW installed wind power
33	Metrics-Wind	Wind - Current actual commodity produced-Electricity-PJ/yr	11	AESO 2012 31.2% capacity factor
42	Metrics-Wind	Wind - Commodity Production if all Alberta Primary Source is Converted to Commodity-Electricity-MWh	12	Assume 25% of 285,000 turbines (@2.3 MW, 35% utilization) based on 20 MM hectares, 70 hectare/turbine
64	Metrics-Wind	Wind - Net Energy Ratio-Electricity-GJ/GJ	13	Assume 7.5 m/sec mean wind speed, 34% wind energy capture, 18% losses
79	Metrics-Wind	Wind - Land Use-Electricity-ha/GJ	14	Assume 10 m X 10 m for turbine footprint, 34% wind capture, annual energy at 35% utilization
75	Metrics-Wind	Wind - GHG-Electricity-kg CO2e/GJ	15	DOE/NETL 2012/1536, 30Aug-2012, Skone et. al., operations only
83	Metrics-Wind	Wind - Water Use-Electricity-MM l/GJ	16	CanWEA/Solas, Alberta WindVision Technical Overview Report, May 2013
58	Metrics-Oil	Oil - Available Commodity Production Capacity (Current Installed Capacity) -Transportation Fuels-Barrels/year	2	CanSim - Table 134-0004 Supply and disposition of refined petroleum products, monthly (cubic metres)
62	Metrics-Oil	Oil - Commodity Production if all Alberta Primary Source is Converted to Commodity-Transportation Fuels-Barrels/ye	3	Based on Jacobs EU LCA Work High Conv Refinery - convenitonal crude surrogate is Arab Medium; Mined bitumen via upgrading; in situ via direct refining
46	Metrics-Oil	Oil - Commodity Production if all Alberta Primary Source is Converted to Commodity-Electricity-PJ/yr	4	Electricity - based on 39% efficiency of power plant using crude oil and 3.4% line loss; assume oil and coal have the same efficiencies; Source: Cost and Performance Baseline for Fossil Energy Plants, May 15, 2007 Revised August 2007, NETL
47	Metrics-Oil	Oil - Commodity Production if all Alberta Primary Source is Converted to Commodity-Heat-PJ/yr	5	Heat - based on 85% boiler efficiency
53	Metrics-Oil	Oil - Energy Density-Primary Source (LHV)-GJ/kg	6	Energy content -based on API methodology to calculate LHV using crude gravity, sulfur and nitrogen contents
59	Metrics-Oil	Oil - Energy Consumption-Transportation Fuels-GJ/GJ	7	Energy consumption transport fuels - energy to produce transportation fuels from EU LCA work divided by the energy in the transportation fuels
60	Metrics-Oil	Oil - Efficiency and Energy Consumption-Electricity-GJ/GJ	8	Energy consumption electricity - energy to produce and transport crude oil from EU LCA work divided by the energy in the electrcity
61	Metrics-Oil	Oil - Efficiency and Energy Consumption-Heat-GJ/GJ	9	Energy consumptionheat - energy to produce transportation fuels from EU LCA work divided by the energy in the transportation fuels
63	Metrics-Oil	Oil - Net Energy Ratio-Transportation Fuels-GJ/GJ	10	Net energy ratio transporation - energy in refined products divided by the energy to produce the refined products + the energy in the crude oil; based on EU LCA work
64	Metrics-Oil	Oil - Net Energy Ratio-Electricity-GJ/GJ	11	Net energy ratio heat - energy in electricity divided by the energy lost in producing the electricity + the energy to produce the crude oil + the energy in the crude oil; based on EU LCA work
65	Metrics-Oil	Oil - Net Energy Ratio-Heat-GJ/GJ	12	Net energy ratio heat - energy in heat divided by the energy lost in producing the heat + the energy to produce the crude oil + the energy in the crude oil; based on EU LCA work
67	Metrics-Oil	Oil - Efficiency of power plant conversion-%	13	Efficiency of power plant: assume same effciency as coal: source is from Cost and Performance Baseline for Fossil Energy Plants, May 15, 2007 Revised August 2007, NETL
68	Metrics-Oil	Oil - Electricity-kW-hr/GJ Primary Source	14	GHG emissions - based on EU LCA work to produce gasoline and diesel from crude oil; results are on the basis of gasoline + diesel
70	Metrics-Oil	Oil - Distance delivered from Electricity-km/GJ Primary Source	15	Distance traveled from electricity is based on Nissan Leaf efficiency of
71	Metrics-Oil	Oil - Distance delivered from Transportation Fuels-km/GJ Primary Source	16	Distance traveled from transportation fuels is based on VW Golf IC wngines usingn spark ignition (gasoline) and compression ignition (diesel) - km per weighted Gasoline + Diesel
74	Metrics-Oil	Oil - GHG-Transportation Fuels-kg CO2e/GJ	17	GHG emissions - transportation - based on WTW assessment of crude oils in EU LCA Study. Carbon intensity of transport fuels:Conventional crude assumes a local crude with properties like Arab Medium in an Alberta high conversion refinery; Mined bitumen assumes efficient mining with on site power generation and SCO from a delayed coker refined in an Alberta high conversion refinery; SAGD bitumen assumes 3.0 SOR with on site power generation, production using mechanical lift and water treatment by evaporeation; dilbit shipped to a high conversion Alberta refinery and diluent returned to the bitumen production siteThis calculation assumes SAGD at 2.5 SOR and CSS with 10% higher bitumen production intensity than SAGD. The CI for CHOPS is lower than SAGD per the EU LCA study. The blended CI for G+D from SAGD, CSS, and CHOPs based on the ERCB rates of 49% SAGD, 25% CSS and 26% other, is within 0.5% of the value for SAGD.
75	Metrics-Oil	Oil - GHG-Electricity-kg CO2e/GJ	18	GHG emissions - electricity - uses crude oil production, fuel cycle and transportation GHG from EU LCA Study and electricity gen efficency of 39% and line loss of 3.4%
76	Metrics-Oil	Oil - GHG-Heat-kg Co2e/GJ	19	GHG emissions - heat - based on crude oil production, fuel cycle and transportation from EU LCA Study with 85% boiler efficiency
77	Metrics-Oil	Oil -	20	Land Use - per PJ of commodity energy; source Yeh et al, Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands, Environmental Science and Technology, 2010
82	Metrics-Oil	Oil - Water Use-Transportation Fuels-MM l/GJ	21	Water use - transportation fuel; source: Mielke et al, Water Consumption of EnergyResource Extraction, Processing,and ConversionEnergy Technology Innovation Policy Discussion Paper SeriesDiscussion Paper No. 2010-15October, 2010
83	Metrics-Oil	Oil - Water Use-Electricity-MM l/GJ	22	Water use - electricity - based on 350 gal/Mwh of electricity; source: Meldrum et al, Life cycle water use for electricity generation: a review and harmonization of literature estimates Environ. Res. Lett. 8 (2013) 015031 (18pp)
84	Metrics-Oil	Oil - Water Use-Heat-MM l/GJ	23	Water use - heat - assume the consumption is the same as for transport fuels

Table 6.2 (cont)
Energy Metrics Comparison – Assumptions and Further Description-2

Row on Metrics Master	Originating Sheet	Tag	Note	Description
9	Metrics-Coal	Coal - Remaining Established Reserve Potential, Primary Source	1	ERCB ST98-13 - Remaining reserves - Table R 8.1: Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2012a (Gt). Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
11	Metrics-Coal	Coal - Actual Annual Production, Primary Source	2	ERCB ST98-13 - Marketable Coal; total energy from Table to produce Figure 1 in ST-98-13; energy breakdown between coal types is based on total energy of 598 PJ/yr, the heating valueand tons of bituminous coal, the tons of sub-bituminous coal and fit of HV of sub-bituminous coal to match overall 598 PJ/yr of coal.
13	Metrics-Coal	Coal - Actual Annual Production, Primary Source -Coal, Uranium-MT	3	ERCB ST98-13 - Figure S8.2: Marketable Coal - 2012 production of sub-bituminous coal + thermal and metallurgic bituminous coal
20	Metrics-Coal	Coal - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-MW	4	AESO long term energy outlook Excel file on website: [UPDATED_2012_Long-term_Outlook_Data_File.xlsx]; extrapolation of 2011 data based on linear interpolation between 2011 and 2017 data
24	Metrics-Coal	Coal - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-PJ/yr	5	Electricity capacity in PJ/yr is calculated from MWh of capacity using on stream factor of 24 hr/day and 35 days per year
33	Metrics-Coal	Coal - Current actual commodity produced-Electricity-PJ/yr	6	AESO - 2012 annual statitistics file - Alberta Electric System Operator 2012 Annual Market Statistics - 2012_Annual_Market_Stats_Data_File.xlsx
37	Metrics-Coal	Coal - Availalble Commodity % of Alberta Consumption-Electricity-%	7	Coal as a percent of 2012 Alberta electricity generation based on 272 PJ/yr (75,457 GWh) of electricity generation/demand - including on site, behind the fence generation
46	Metrics-Coal	Coal - Commodity Production if all Alberta Primary Source is Converted to Commodity-Electricity-PJ/yr	8	Based on a blended electricity generation: current capacity at 39% efficiency; new capacity with CCS at 27% efficiency; plus 3.4% line loss
47	Metrics-Coal	Coal - Commodity Production if all Alberta Primary Source is Converted to Commodity-Heat-PJ/yr	9	Generation of heat at 85% efficiency
50	Metrics-Coal	Coal - Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption-Ele	10	Alberta electricity generation potential based on 2012 demand of 272 PJ/yr and 198 PJ/yr of potential generation based on blended rate from Note 8
51	Metrics-Coal	Coal - Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consumption-He	11	Alberta heat generation potential based on 1260 PJ/yr of heat and 2012 coal and 85% efficiency
53	Metrics-Coal	Coal - Energy Density-Primary Source (LHV)-GJ/kg	12	Heating value of coal is a blended value based on heating values of bituminous and sub-bituminous coal and 2012rates of coal production
60	Metrics-Coal	Coal - Efficiency and Energy Consumption-Electricity-GJ/GJ	13	Energy consumption - electricity generation - based on difference between energy in coal delivered to plant and electricity delivered at city gate divided by the energy in coal delivered
64	Metrics-Coal	Coal - Net Energy Ratio-Electricity-GJ/GJ	14	Net energy ratio electricity - based on electricial energy produced from coal delivered to plant divided by the energy in coal delivered and difference between energy in coal delivered and electricity produced from coal delivered
65	Metrics-Coal	Coal - Net Energy Ratio-Heat-GJ/GJ	15	Net energy ratio heat - based on heat produced from coal delivered to plant divided by the energy in coal delivered and difference between energy in coal delivered and heat produced from coal delivered
67	Metrics-Coal	Coal - Efficiency of power plant conversion-%	16	Power plant efficiency is based of 39% w/o CCS and 27% w CCS; source: Cost and Performance Baseline for Fossil Energy Plants, May 15, 2007 Revised August 2007, NETL
68	Metrics-Coal	Coal - Electricity-kW-hr/GJ Primary Source	17	Electricity generation is based on efficiency of electricity from coal w and w/o CCS and 3.4% line loss - see source in Note 16
70	Metrics-Coal	Coal - Distance delivered from Electricity-km/GJ Primary Source	18	Distance from electricity - based on power output for existing plants and new plants with CCS and Nissan Leaf efficiency of 34 kwh/100 mi from EPA mileage estimates
75	Metrics-Coal	Coal - GHG-Electricity-kg CO2e/GJ	19	GHG for electricty from coal is based on GHG estimates for mine to power plant delivery of coal and delivery of electricity to city gate assuming 3.4% line loss. Power plants are assumed to be 39% efficient for existing and 27% efficient for new plants with CCS. Uses exsing bituminous/sub-bituminous coal production split
76	Metrics-Coal	Coal - GHG-Heat-kg Co2e/GJ	20	GHG for heat - based on coal mix produced, 85% efficiency of boiler and GHG emisisons from mine to heat generation (assumed to be the same as in power generation)
79	Metrics-Coal	Coal - Land Use-Electricity-ha/GJ	21	Land use electricity - Based on2010 estimate of Alberta land in coal mininng: 31,000 ha under mining minus 15,500 ha that have been reclaimed; divided by the coal production in AB in 2010 of 38.5 MM t/yr and 24.4 GJ/tonne heating value; and 37.7% efficiency of electricity generation
80	Metrics-Coal	Coal - Land Use-Heat-ha/GJ	22	Land use heat - Based on2010 estimate of Alberta land in coal mininng: 31,000 ha under mining minus 15,500 ha that have been reclaimed; divided by the coal production in AB in 2010 of 38.5 MM t/yr and 24.4 GJ/tonne heating value; and 85% efficiency of heat generation
83	Metrics-Coal	Coal - Water Use-Electricity-MM l/GJ	23	Water use electricity - based on 550 gal/MWh of electricity generation, which is from: Meldrum, et al, Life cycle water use for electricitygeneration: a review and harmonizationof literature estimatesEnviron. Res. Lett. 8 (2013) 015031 (18pp)41345
84	Metrics-Coal	Coal - Water Use-Heat-MM l/GJ	24	Water use for generating heat - water to wash and clean coal plus 20% of the water use in electricity generation - adjusted b y the efficiency differences for electricity and heat
87	Metrics-Coal	Coal - Air emissions-Electricity-kg/GJ	25	Air emissions from electricity from coal - based on 21 kg/GWh; source: Table 32 in Spath et al., Life Cycle Assessment ofCoal-fired Power Production Including contributions on process definition and data acquisition from: John Marano and Massood RamezanFederal Energy Technology CenterJune 1999 • NREL/TP-570-25119
88	Metrics-Coal	Coal - Air emissions-Heat-kg/GJ	26	Air emissions heat - use air emissions for electricity generation and adjust based on ratio of efficiencies for heat and power
91	Metrics-Coal	Coal - Solids emissions-Electricity-kg/GJ	27	Solids emissions from electricity from coal - based on 21 kg/GWh; source: Table 21 in Spath et al., Life Cycle Assessment ofCoal-fired Power Production Including contributions on process definition and data acquisition from: John Marano and Massood RamezanFederal Energy Technology CenterJune 1999 • NREL/TP-570-25119
92	Metrics-Coal	Coal - Solids emissions-Heat-kg/GJ	28	Solids emissions heat - use solids emissions for electricity generation and adjust based on ratio of efficiencies for heat and power

Table 6.2 (cont)
Energy Metrics Comparison – Assumptions and Further Description-3

Row on Metrics Master	Originating Sheet	Tag	Note	Description
53	Metrics-Nuclear	Nuclear - Energy Density-Primary Source (LHV)-GJ/kg	1	3.5 wt % enrichment in LWR
60	Metrics-Nuclear	Nuclear - Efficiency and Energy Consumption-Electricity-GJ/GJ	2	thermal efficiency = 33%; source: NETL TAR Report
64	Metrics-Nuclear	Nuclear - Net Energy Ratio-Electricity-GJ/GJ	3	thermal efficiency = 33%; source: NETL TAR Report
68	Metrics-Nuclear	Nuclear - Electricity-kW-hr/GJ Primary Source	4	Delivered at city gate
70	Metrics-Nuclear	Nuclear - Distance delivered from Electricity-km/GJ Primary Source	5	Based on Nissan Leaf
75	Metrics-Nuclear	Nuclear - GHG-Electricity-kg CO2e/GJ	6	meta study, LWR - HWR reactors, operational phase only, source: Yale University study Meta analysis LCA GHG Nuclear Power
79	Metrics-Nuclear	Nuclear - Land Use-Electricity-ha/GJ	7	default enrichment mix, weighted average of mining / ISL, source: NETL TAR
83	Metrics-Nuclear	Nuclear - Water Use-Electricity-MM l/GJ	8	average of high and low estimates based on open and closed loop cooling,source: Harvard study, Water use in Power generation
87	Metrics-Nuclear	Nuclear - Air emissions-Electricity-kg/GJ	9	default enrichment mix, weighted average of mining / ISL, existing power plant, source: NETL TAR
91	Metrics-Nuclear	Nuclear - Solids emissions-Electricity-kg/GJ	10	default enrichment mix, weighted average of mining / ISL, source: NETL TAR
9	Metrics-Natural Gas	Natural Gas - Remaining Established Reserve Potential, Primary Source	1	ERCB ST98-13 - Table R5.1 Reserve and production changes in marketable conventional gas (109 m3)
11	Metrics-Natural Gas	Natural Gas - Actual Annual Production, Primary Source	2	ERCB ST98-13 - Natural gas from coal bed methane and conventional gas - w/o shale gas; total energy from Table to produce Figure 1 in ST-98-13
14	Metrics-Natural Gas	Natural Gas - Actual Annual Production, Primary Source -Natural Gas-scfd	3	ERCB ST98-13 - Figure 13:Total Marketable Gas Production and Demand - data for 2012
20	Metrics-Natural Gas	Natural Gas - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-MW	4	AESO long term energy outlook Excel file on website: [UPDATED_2012_Long-term_Outlook_Data_File.xlsx]; extrapolation of 2011 data based on linear interpolation between 2011 and 2017 data
24	Metrics-Natural Gas	Natural Gas - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-PJ/yr	5	Electricity capacity in PJ/yr is calculated from MWh of capacity using on stream factor of 24 hr/day and 35 days per year
33	Metrics-Natural Gas	Natural Gas - Current actual commodity produced-Electricity-PJ/yr	6	AESO - 2012 annual statitistics file - Alberta Electric System Operator 2012 Annual Market Statistics - 2012_Annual_Market_Stats_Data_File.xlsx - sum of on site gas fired cogen at oil sands facilities plus gas and cogen that is part of the AESO system
37	Metrics-Natural Gas	Natural Gas - Availalble Commodity % of Alberta Consumption-Electricity-%	7	Natural gas as a percent of 2012 Alberta electricity generation based on 272 PJ/yr (75,457 GWh) of electricity generation/demand - including on site, behind the fence generation
38	Metrics-Natural Gas	Natural Gas - Availalble Commodity % of Alberta Consumption-Heat-%	8	Natural gas supply of heat is based on an estimate of gas use in Alberta not used for electricity generaton plus an estimate of residential biomass use in heating from Households and the Environment: Energy Use, Statistics Canada - Environment Accounts and Statistics Division, 2007 and ratio up to 2012
46	Metrics-Natural Gas	Natural Gas - Commodity Production if all Alberta Primary Source is Converted to Commodity-Electricity-PJ/yr	9	Maxium electricity production from natural gas - assumes 51% efficiency
50	Metrics-Natural Gas	Natural Gas - Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consump	10	Maxium electricity potential as % of current demand is based on 272 PJ/yr of electricity demand in Alberta
51	Metrics-Natural Gas	Natural Gas - Commodity Production if all Alberta Primary Source is Converted to Commodity, % of Alberta Consump	11	Maxium heat potential as % of current demand is based on 12670 PJ/yr of heat demand in Alberta
53	Metrics-Natural Gas	Natural Gas - Energy Density-Primary Source (LHV)-GJ/kg	12	LHV - GREET Transportation Fuel Cycle Analysis Model, GREET 1.8b, developed by Argonne National Laboratory, Argonne, IL, released May 8, 2008.
54	Metrics-Natural Gas	Natural Gas - Energy Density-Primary Source (HHV)-GJ/kg	13	HHV - GREET Transportation Fuel Cycle Analysis Model, GREET 1.8b, developed by Argonne National Laboratory, Argonne, IL, released May 8, 2008.
59	Metrics-Natural Gas	Natural Gas - Energy Consumption-Transportation Fuels-GJ/GJ	14	Energy consumption to deliver natural gas transportation fuels varies between 10% and 13% of energy in natural gas in the field - Skone et al, Life Cycle Assessment of Natural Gas Extraction, Delivery and Electricity Production, NETL, 2012
60	Metrics-Natural Gas	Natural Gas - Efficiency and Energy Consumption-Electricity-GJ/GJ	15	Energy consumption to deliver electricity from natural gas based on 51% efficincy of combined cycle plus the losses in delivering natural gas, which varies between 10% and 13% of energy in natural gas in the field - Skone et al, Life Cycle Assessment of Natural Gas Extraction, Delivery and Electricity Production, NETL, 2013
61	Metrics-Natural Gas	Natural Gas - Efficiency and Energy Consumption-Heat-GJ/GJ	16	Energy consumption to deliver heat from natural gas based on 85% efficincy of boiler plus the losses in delivering natural gas, which varies between 10% and 13% of energy in natural gas in the field - Skone et al, Life Cycle Assessment of Natural Gas Extraction, Delivery and Electricity Production, NETL, 2013
63	Metrics-Natural Gas	Natural Gas - Net Energy Ratio-Transportation Fuels-GJ/GJ	17	Net energy of transportation fuels is based on 10% loss in producing and delivering natural gas from field to the user
64	Metrics-Natural Gas	Natural Gas - Net Energy Ratio-Electricity-GJ/GJ	18	Net energy of heat is based on 85% efficiency of combined cycle and 10% loss of natural gas in delivering natural gas from field to user
65	Metrics-Natural Gas	Natural Gas - Net Energy Ratio-Heat-GJ/GJ	19	Net energy of electricity is based on 51% efficiency of combined cycle and 10% loss of natural gas in delivering natural gas from field to user
67	Metrics-Natural Gas	Natural Gas - Efficiency of power plant conversion-%	20	Distance from electricity is based on 51% efficiency of combined cycle natural gas powered plant and Nissan Leaf combined city and highway mileage of 34 kwh/100 miles (USEPA)
70	Metrics-Natural Gas	Natural Gas - Distance delivered from Electricity-km/GJ Primary Source	21	Distance traveled for hydrocarbons - based on 26 miles/gallon combined city and highway driving for VW Golf (US EPA) Assumed a GJ of gasoline and GJ of natural gas are equivalent
71	Metrics-Natural Gas	Natural Gas - Distance delivered from Transportation Fuels-km/GJ Primary Source	22	GHG for gtransporation is ~ 55 g CO2e/MJ from combustion + 9 g CO2e/MJ for production and delivery of natural gas
75	Metrics-Natural Gas	Natural Gas - GHG-Electricity-kg CO2e/GJ	23	GHG for electricity is GHG from combustion and fuel cycle divided by the efficiency of electricty generation from combined cycle (51%)
76	Metrics-Natural Gas	Natural Gas - GHG-Heat-kg Co2e/GJ	24	GHG for electricity is GHG from combustion and fuel cycle divided by the efficiency of heat generation (85%)
82	Metrics-Natural Gas	Natural Gas - Water Use-Transportation Fuels-MM l/GJ	25	Water use - transportation fuel; source: Mielke et al, Water Consumption of Energy Resource Extraction, Processing,and ConversionEnergy Technology Innovation Policy Discussion Paper SeriesDiscussion Paper No. 2010-15October, 2010
83	Metrics-Natural Gas	Natural Gas - Water Use-Electricity-MM l/GJ	26	Water use electricity - based on 250 gal/MWh of electricity generation, which is from: Meldrum, et al, Life cycle water use for electricitygeneration: a review and harmonizationof literature estimatesEnviron. Res. Lett. 8 (2013) 015031 (18pp)41345; includes water for natural gas extraction and transport
84	Metrics-Natural Gas	Natural Gas - Water Use-Heat-MM l/GJ	27	Water use for heat is assumed to be 20% of the rate for electricity production

Table 6.2 (cont)
Energy Metrics Comparison – Assumptions and Further Description-4

Row on Metrics Master	Originating Sheet	Tag	Note	Description
11	Metrics-MSW	MSW / Landfill - Actual Annual Production, Primary Source	1	Modelled in LandGem model, assumed all Alberta MSW is in a 20 year old landfill, model output includes calculated landfill gas emissions
24	Metrics-MSW	MSW / Landfill - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-PJ/yr	2	Assumes 365 d/yr / 24 h/d operation
92	Metrics-MSW	MSW / Landfill - Solids emissions-Heat-kg/GJ	3	Slag = approximately 25% of MSW weight
75	Metrics-MSW	MSW / Landfill - GHG-Electricity-kg CO2e/GJ	4	Zero out GHG for biomass combustion and anaerobic digestion because on an LCA basis these values should be close to 0 except for hydrocarbon fuels and chemicals used in production and land use - which is still under development and not finalized
20	Metrics-Solar	Solar - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-MW	2	Installed distributed Solar PV, source: CanSIA
42	Metrics-Solar	Solar - Commodity Production if all Alberta Primary Source is Converted to Commodity-Electricity-MWh	3	Assumes installations in all viable rooftops in residential, farm and commercial/industrial buildings. Solar Utility assumes all crop and pastureland covered in solar panels at 8 acre/MW. Insolation of 1200 kWh/KW
60	Metrics-Solar	Solar - Efficiency and Energy Consumption-Electricity-GJ/GJ	4	Does not include energy to construct solar panels
64	Metrics-Solar	Solar - Net Energy Ratio-Electricity-GJ/GJ	5	Assume solar cell efficiency of 13%, conversion efficiency of 77%, no line losses for distributed PV, 3.4 % line losses for utility PV
79	Metrics-Solar	Solar - Land Use-Electricity-ha/GJ	6	Assume installed PV units of 8 acres / MW as per CanSIA
10	Metrics-Biomass	Biomass - Maximum Possible Production, Primary Source	1	Maximum Possible Production, Primary Source - e.g. for oil it is the total annual production; for bioamss for ethanol it is the total annual production of seed crops that can be fermented
11	Metrics-Biomass	Biomass - Actual Annual Production, Primary Source	2	Actual Annual Production, Primary Source - e.g. for oil it is the total annual production; for bioamss for ethanol it is the total annual production of seed crops that can be fermented to produce the annual prodution of ethanol
15	Metrics-Biomass	Biomass - Actual Annual Production, Primary Source -Biomass, MSW, Landfill Gas-MT	3	Anaerobic Digestion is based on the biomethane produced from 32,000 MT of manure
20	Metrics-Biomass	Biomass - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-MW	4	For biomass combustion and anaerobic digestion there are units that produce steam and electricity to the grid, capacities are reported in terms of MW
24	Metrics-Biomass	Biomass - Available Commodity Production Capacity (Current Installed Capacity) -Electricity-PJ/yr	5	For biomass combustion and anaerobic digestion there are units that produce steam and electricity to the grid, capacities are reported in terms of MW
41	Metrics-Biomass	Biomass - Commodity Production if all Alberta Primary Source is Converted to Commodity-Transportation Fuels-Barre	6	Bioethanol production assumes conventional fermentation technology with wheat, corn, barley and tame hay. Biodiesel production assumes production of methyl ester based on canola oil
79	Metrics-Biomass	Biomass - Land Use-Electricity-ha/GJ	7	Land use is calculated based on crop land use only. Woody biomass, forest residue and agricultural residue are assumed to have no land use.
80	Metrics-Biomass	Biomass - Land Use-Heat-ha/GJ	8	Land use is calculated based on crop land use only. Woody biomass, forest residue and agricultural residue are assumed to have no land use.
82	Metrics-Biomass	Biomass - Water Use-Transportation Fuels-MM l/GJ	9	Water use for biofuels includes agricultural water use and conversion water use. Source: Singh, Kumar, 2011
84	Metrics-Biomass	Biomass - Water Use-Heat-MM l/GJ	10	Biomass combustion water use assumes no irrigation of biomass. Source: Singh, Kumar, 2011
84	Metrics-Biomass	Biomass - Water Use-Heat-MM l/GJ	11	Water use for anaerobic digestion includes water for manure flushing
75	Metrics-Biomass	Biomass - GHG-Electricity-kg CO2e/GJ	12	Zero out GHG for biomass combustion and anaerobic digestion because on an LCA basis these values should be close to 0 except for hydrocarbon fuels and chemicals used in production and land use - which is still under development and not finalized
42	Metrics-Hydro	Hydro - Commodity Production if all Alberta Primary Source is Converted to Commodity-Electricity-MWh	1	Ultimately developable hydroelectric potential. Source: Hatch
64	Metrics-Hydro	Hydro - Net Energy Ratio-Electricity-GJ/GJ	2	Source: Hatch
67	Metrics-Hydro	Hydro - Efficiency of power plant conversion-%	3	Source: Hatch
75	Metrics-Hydro	Hydro - GHG-Electricity-kg CO2e/GJ	4	Land use change and methane emissions from reservoirs
79	Metrics-Hydro	Hydro - Land Use-Electricity-ha/GJ	5	Land use includes reservoir units only.
83	Metrics-Hydro	Hydro - Water Use-Electricity-MM l/GJ	6	Evaporation from reservoirs. Reservoir and climate dependent.

Table 6.3.
Notes for Table 6.1

1. Bitumen reserves split: 20% mining and 80% in situ in this table per ERCB data; In situ assumes 49% from steam assisted gravity and drainage (SAGD), 25% from cyclic steam stimulation (CSS) and 26% from other, which is non thermal. Cold heavy oil production with sand (CHOPS) has been assumed for other, non thermal production in this Study
2. Actual Annual Production, Primary Source - e.g. for oil it is the total annual production; for biomass for ethanol it is the total annual production of seed crops that can be fermented to produce the annual production of ethanol
3. Transportation fuels include gasoline, diesel, bioethanol and biodiesel.
4. Includes offsite co-gen, source: AUC, ERCB
5. Electricity production capacity - PJ/yr based on 365 days per year
6. Current Alberta consumption of electricity from AESO in 2012 is 75,000 GWh/yr (272 PJ/yr) with an electricity import of 3,600 GWh (13 PJ/yr) in 2012
7. Current Alberta transport fuels are not broken out by crude source in line 30
8. Maximum Possible Production, Primary Source - e.g. for oil it is the total annual production; for biomass for ethanol it is the total annual production of seed crops that can be fermented
9. Energy Consumption = Energy to convert primary source to commodity / Energy in the Commodity, does not include the energy to build the conversion facility; Includes line losses to bring electricity to city gate
10. Electricity from coal assumes that current production continues without carbon capture and storage (CCS) at 39% efficiency. Additional generation of electricity from coal assumes CCS and efficiencies of27%
11. Net Energy Ratio = Energy in the Commodity / (Energy to convert primary source to commodity + energy in the Primary Source), does not include the energy to build the conversion facility
12. Bioethanol production assumes conventional fermentation technology with wheat, corn, barley and tame hay.
13. GHG emissions for transport fuels are Well-to wheels emissions
14. Land density = land disturbed by the pathway process only. It does not include transmission line land use.

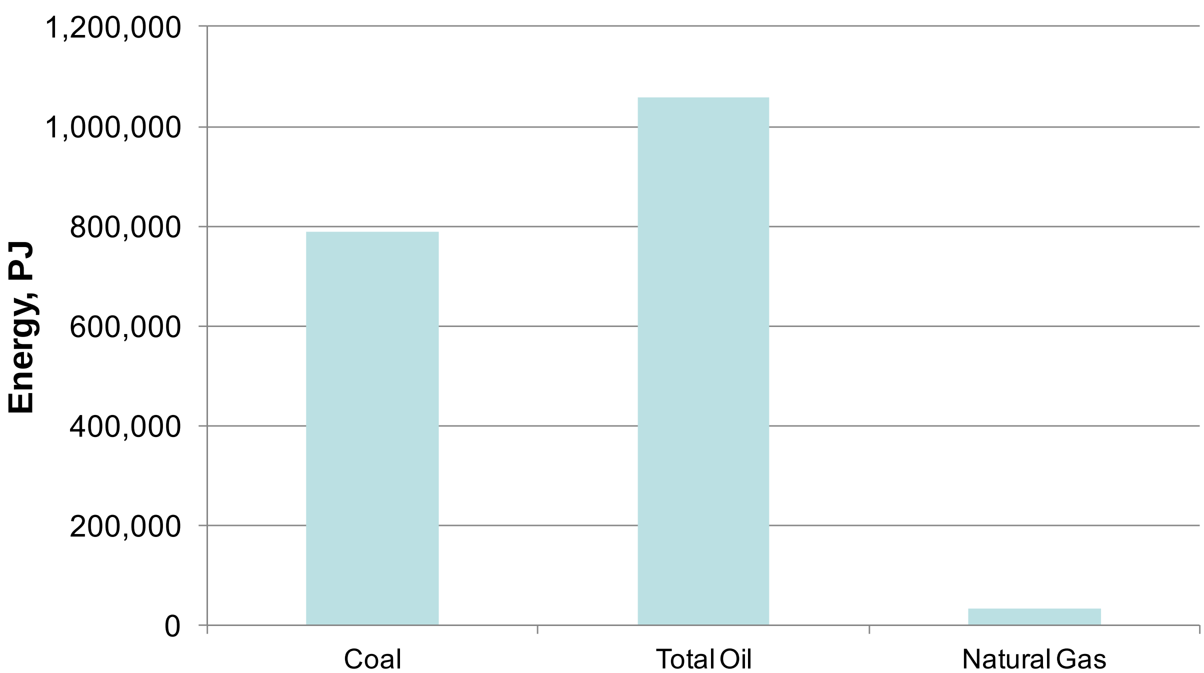
Metrics Comparison Discussion

In the following sections, we compare some of the key metrics.

Remaining Established Reserve Potential, Primary Source

The established reserve potential applies to stock energy resources and describes how much of the energy source is available for future extraction. Alberta has abundant established reserves of bitumen and coal, much less of natural gas. (ERCB, ST-98, 2013). Figure 6.1 shows the established reserve potential in PJ for coal, conventional oil, bitumen, and natural gas. The estimate of established reserve potential does not include undeveloped resources, which may have great potential, such as oil and gas from shale deposits and gas from other tight resources. In subsequent discussion, we will combine conventional crude and bitumen into one bar called Total Oil.

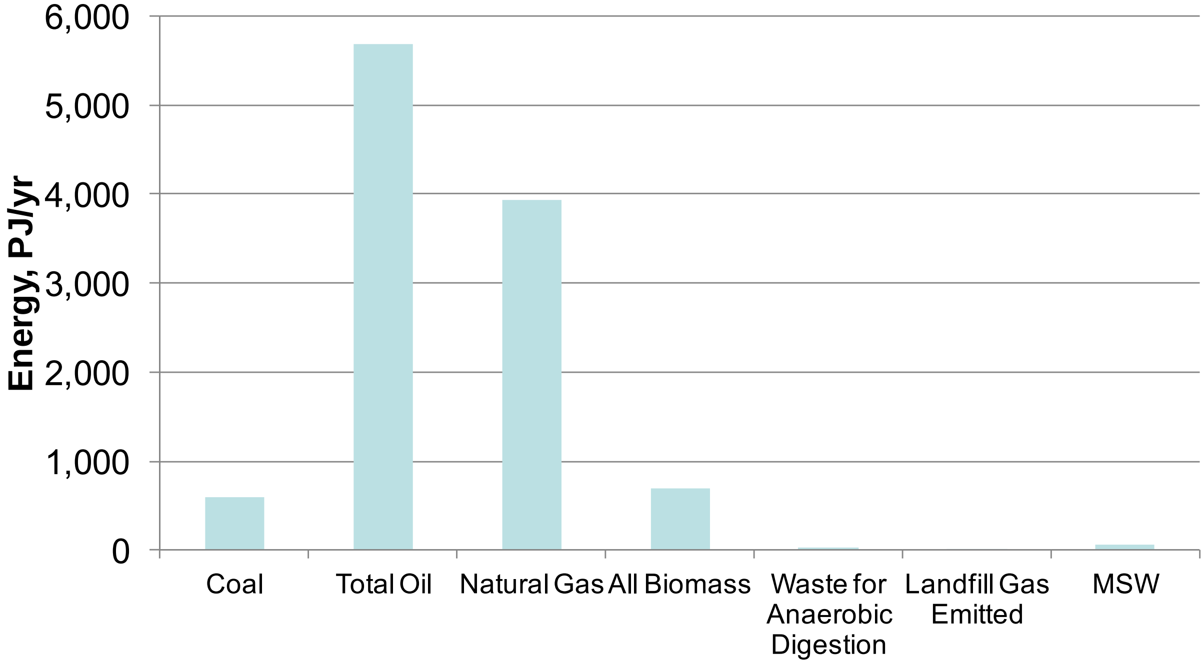
Figure 6.1
Remaining Established Reserve Potential - Primary Source



Actual Annual Production, Primary Source

Annual production of the primary energy sources is shown in Figure 6.2. The units are in PJ/yr. Alberta produces more natural gas than any other energy resource.

Figure 6.2.
Actual Annual Production of Each Primary Energy Resource



Actual Annual Production

Table 6.4 shows current actual production of commodities in Alberta. Alberta exports some transportation fuel products and imports some electricity from other grids.

Table 6.4
Current Commodity Production in Alberta

Current actual commodity produced	Units	Alberta Demand	Alberta Production
Conventional Units			
Transportation Fuels	MM Bbls/yr	86	127
Electricity	GWh/yr	75,500	70,200
Heat	PJ/yr	1,260	1,260
Energy Basis			
Transportation Fuels	PJ/yr	468	696
Electricity	PJ/yr	272	253
Heat	PJ/yr	1,260	1,260

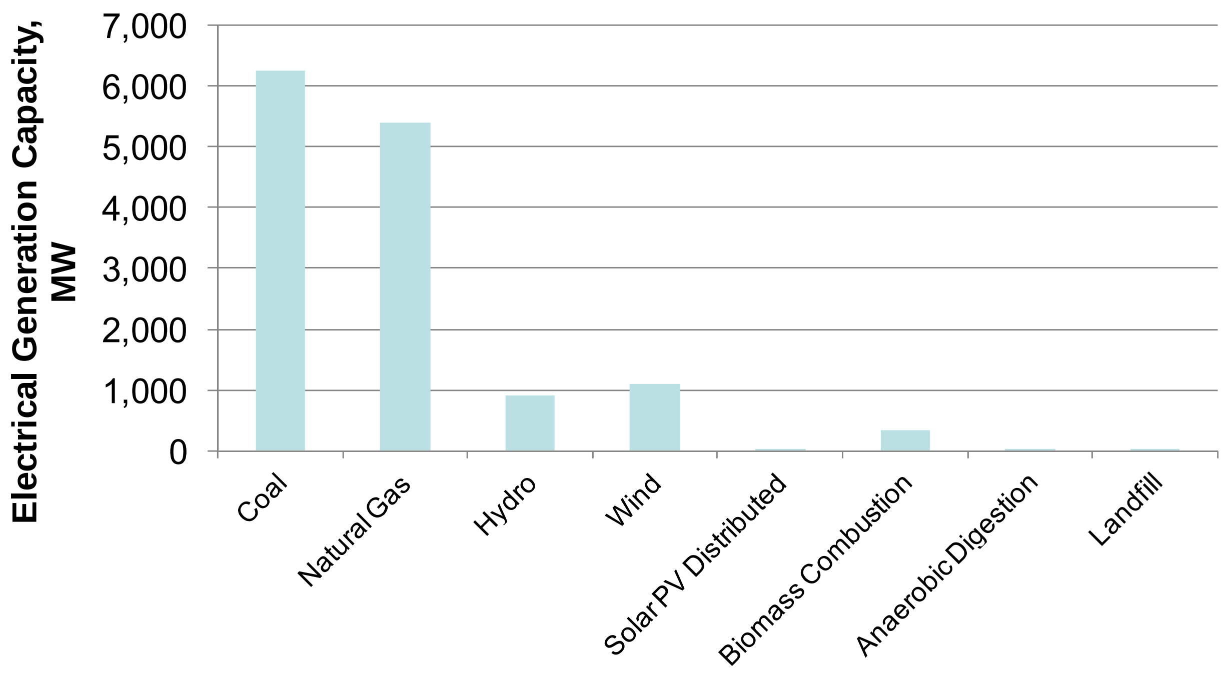
Since oil is the dominant energy source for transportation fuels and natural gas is the dominant energy source for heat, we now focus on electric power, which has a number of primary energy sources in Alberta.

Available Production Capacity - Electricity

This metric gives a measure of the installed capacity to generate electricity in Alberta. . It does not measure the actual production of electricity.

Figure 6.3 shows us that although capacity exists in Alberta to generate electricity via energy resources such as solar photovoltaic distributed, anaerobic digestion, and landfill gas, the amount of electrical generation capacity that these resources represent is small compared to the generation capacity from coal and natural gas.

Figure 6.3.
Available Electricity Generation Capacity



Actual Annual Production -Electricity

The next metric measures actual annual production of electricity in Alberta. This metric is first expressed in standard units and then as a percent of total Alberta electricity demand. Imports make up a portion of the electricity supply in Alberta. Figure 6.4 shows the actual production of electricity in Alberta from the different energy sources, expressed in GW-hr/yr. Electricity generation is dominated by coal in Alberta. Figure 6.5 shows electricity generation from each source as a percentage of Alberta's total annual demand (272 PJ/yr).

Figure 6.4.
Current Generation of Electricity in Alberta

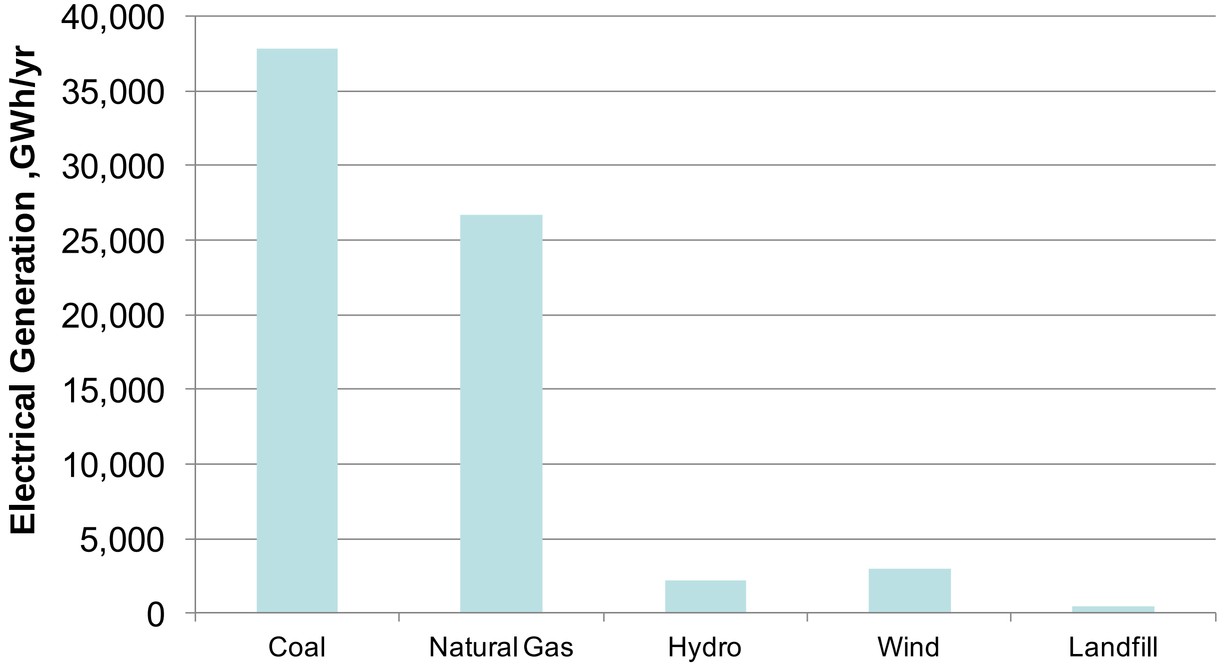
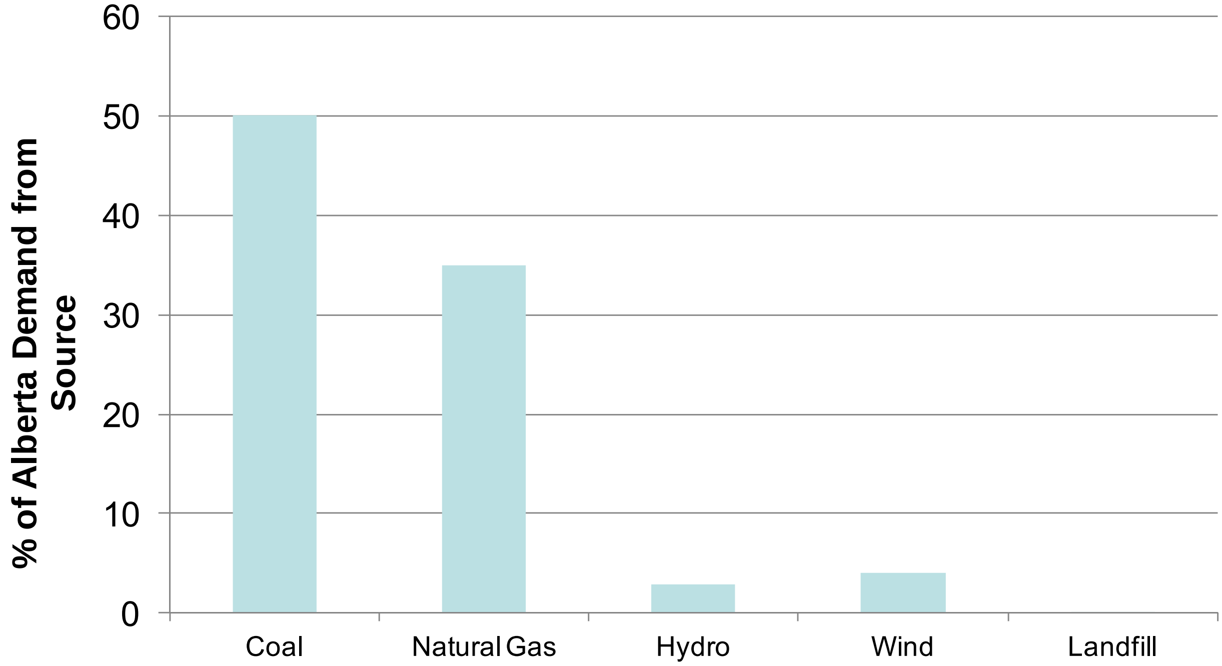


Figure 6.5.
Current Generation of Electricity in Alberta as a Percentage of Alberta Demand



Commodity Production if All Alberta Primary Source Energy is Converted to Commodity Energy

This metric evaluates the potential to supply Alberta's energy needs if the all of the potential primary source is converted to the commodity energy. For stock primary energy resources, namely hydrocarbons, the available primary energy source is based on current annual production. For flow resources (biomass, wind, etc.), we have estimated a maximum annual potential as discussed in Section 5. We begin evaluating the potential to supply transportation, then electricity, and then heat.

Transportation Fuels

Figure 6.6 shows how much transportation fuel can be produced if all the available resource is converted to transportation fuels. The units are MM Barrels/yr. Figure 6.7 shows the percent of Alberta demand that can be supplied in this manner. The assumptions for these metrics are described above in Section 5 and the notes in Table 6.2 and Table 6.3. Biofuels potentially could supply approximately 40% of current demand, but only if all the crops in Alberta were converted to biofuels. We have converted the energy in natural gas to gasoline barrel equivalents based on their heating values.

Figure 6.6.
Production of Transportation Fuels if all of the Resource is Converted to Transport Fuel

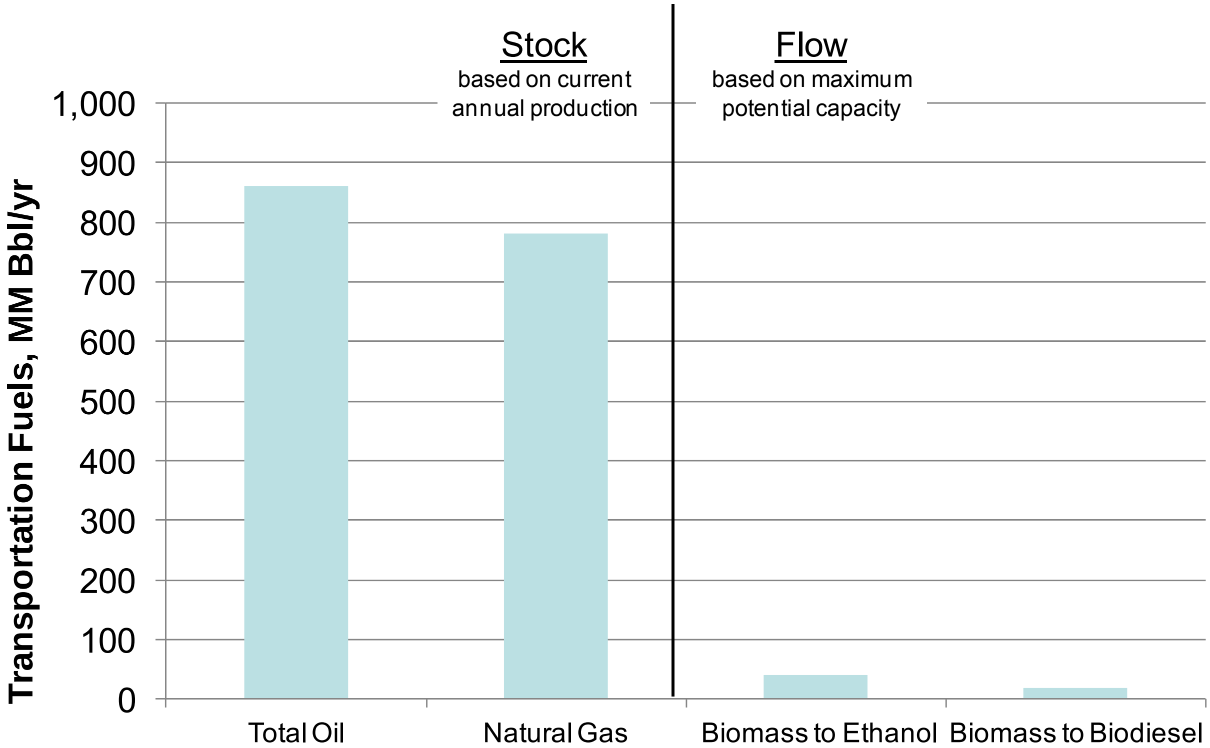
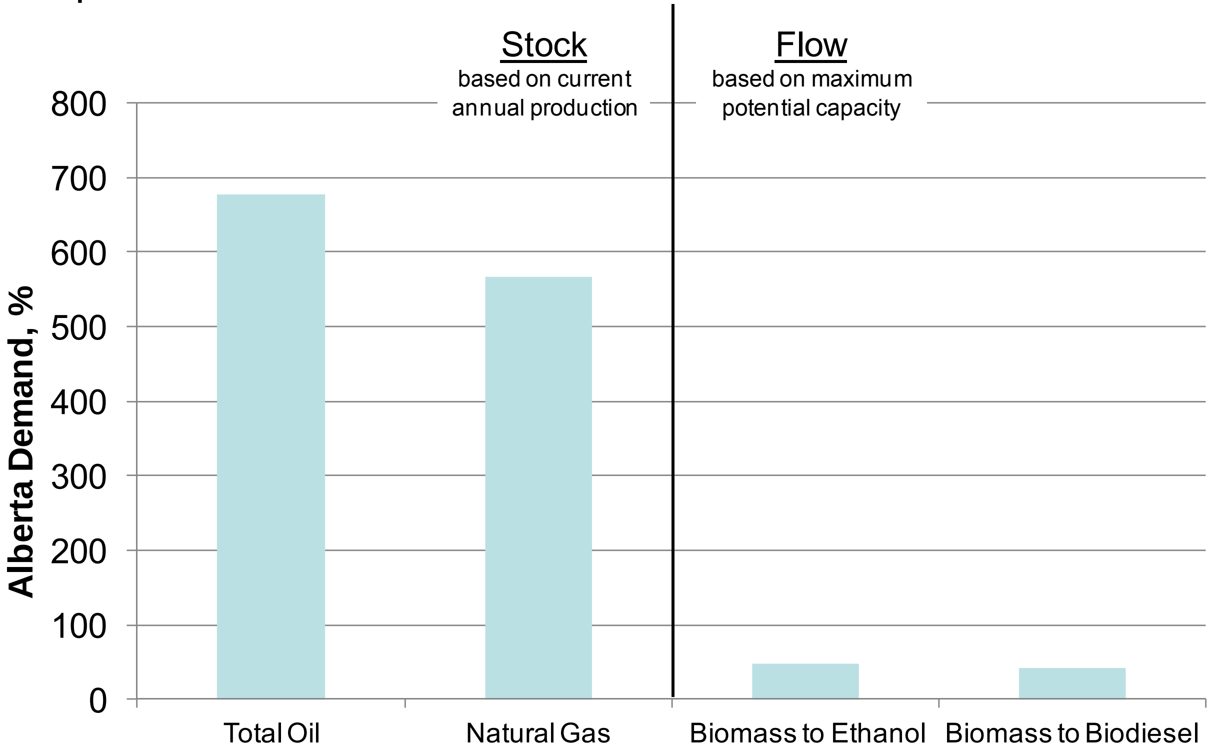


Figure 6.7.
Percent of Alberta Transportation Fuel Demand if all of the Resource is Converted to Transportation Fuel



Electricity

Figure 6.8 shows the production of electricity if all of the primary energy is converted to electricity. Figure 6.9 shows the potential electricity that could be produced on the basis of percent of current Alberta electricity demand. An enormous amount of electrical power could be generated from wind and solar if they were deployed over all the white areas of the province. The potential for Solar PV is read from the right hand axes in these figures.

Figure 6.8.
Electricity Supply if all of the Resource is Converted to Electricity

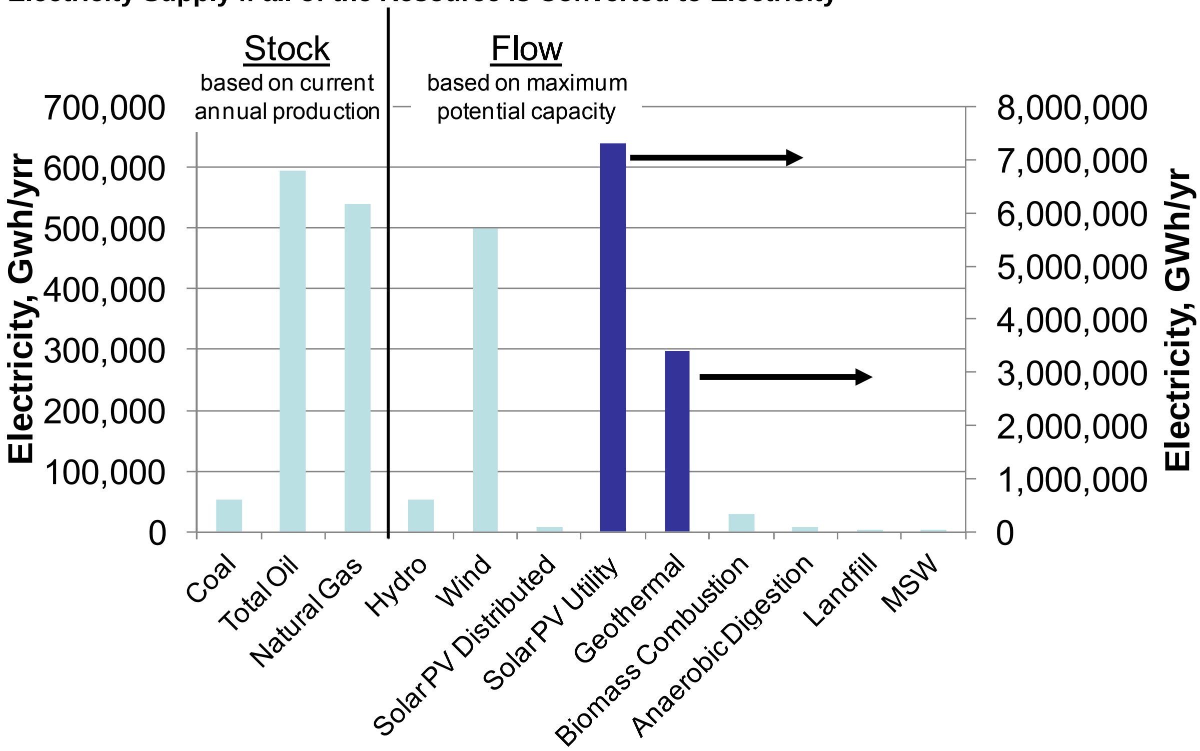
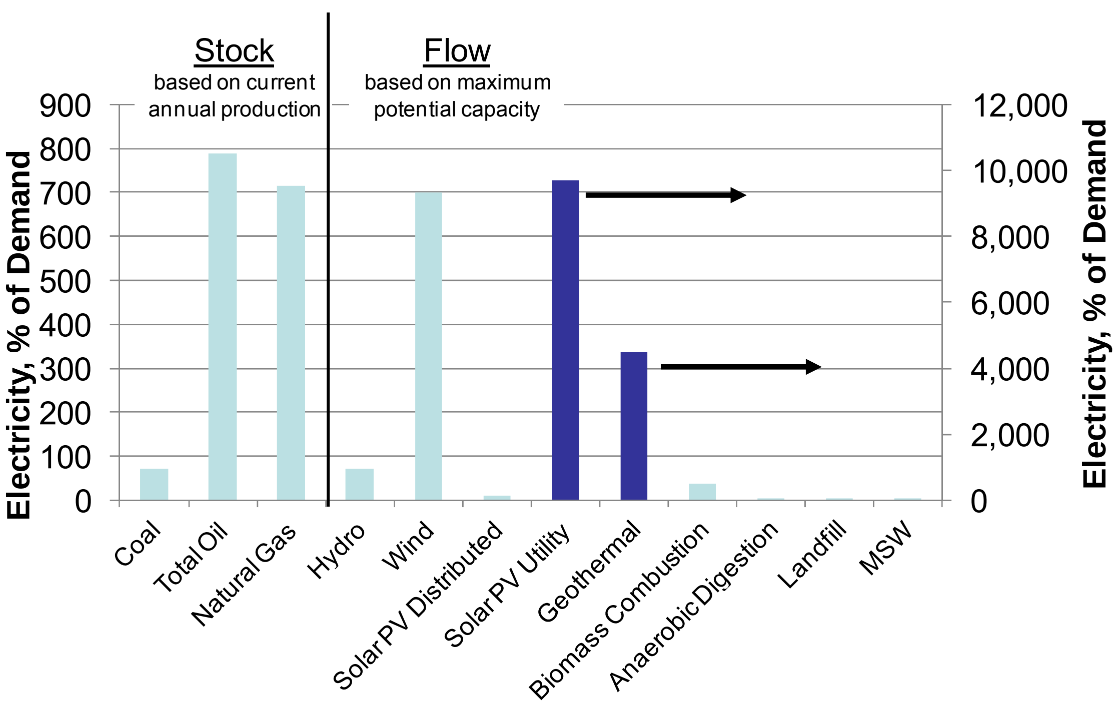


Figure 6.9.
Percent of Alberta Electricity Demand if all of the Resource is Converted to Electricity



Heat

The potential heat that could be produced from the available primary resources is shown in Figure 6.10, if all of each resource is converted to heat. Figure 6.11 shows the amount of heat that could be produced as a percent of Alberta's current heat demand. Natural gas stands out as having the greatest potential to supply heat for Alberta. Landfill gas, anaerobic combustion and MSW potentially could supply heat, but would meet only a small percent of Alberta's heat requirement.

Figure 6.10.
Available Heat if all of the Resource is Converted to Heat

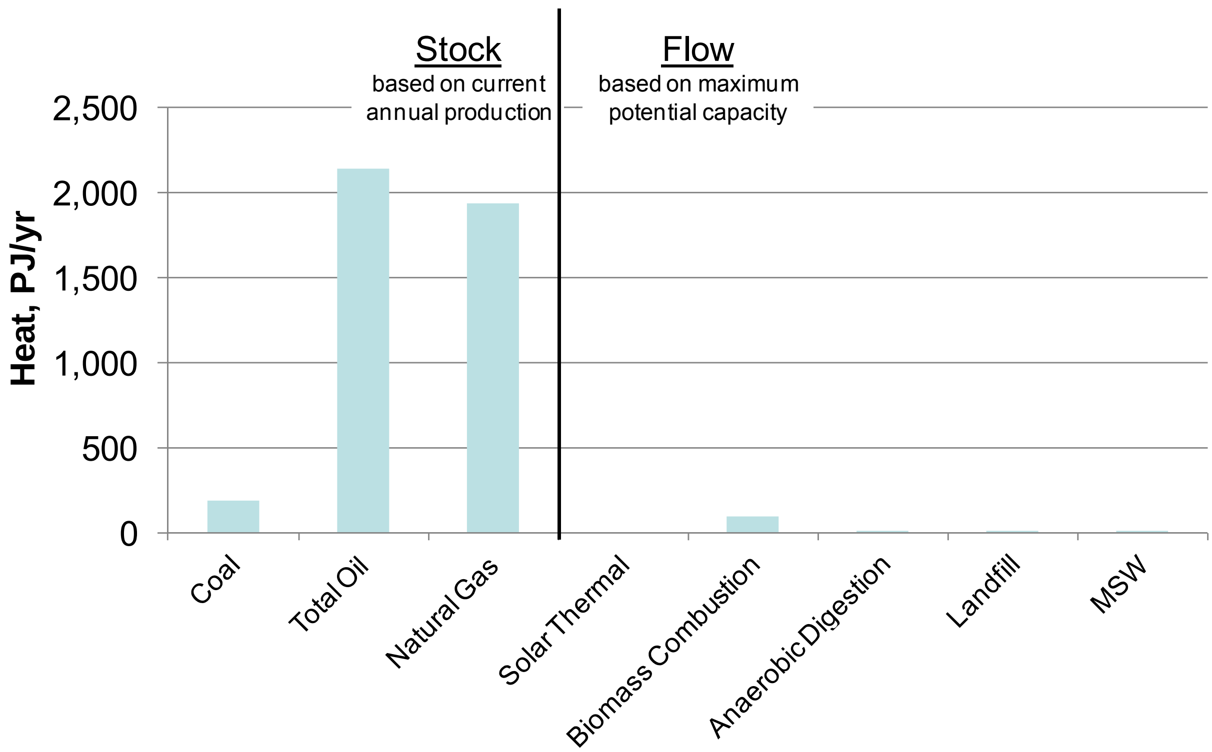
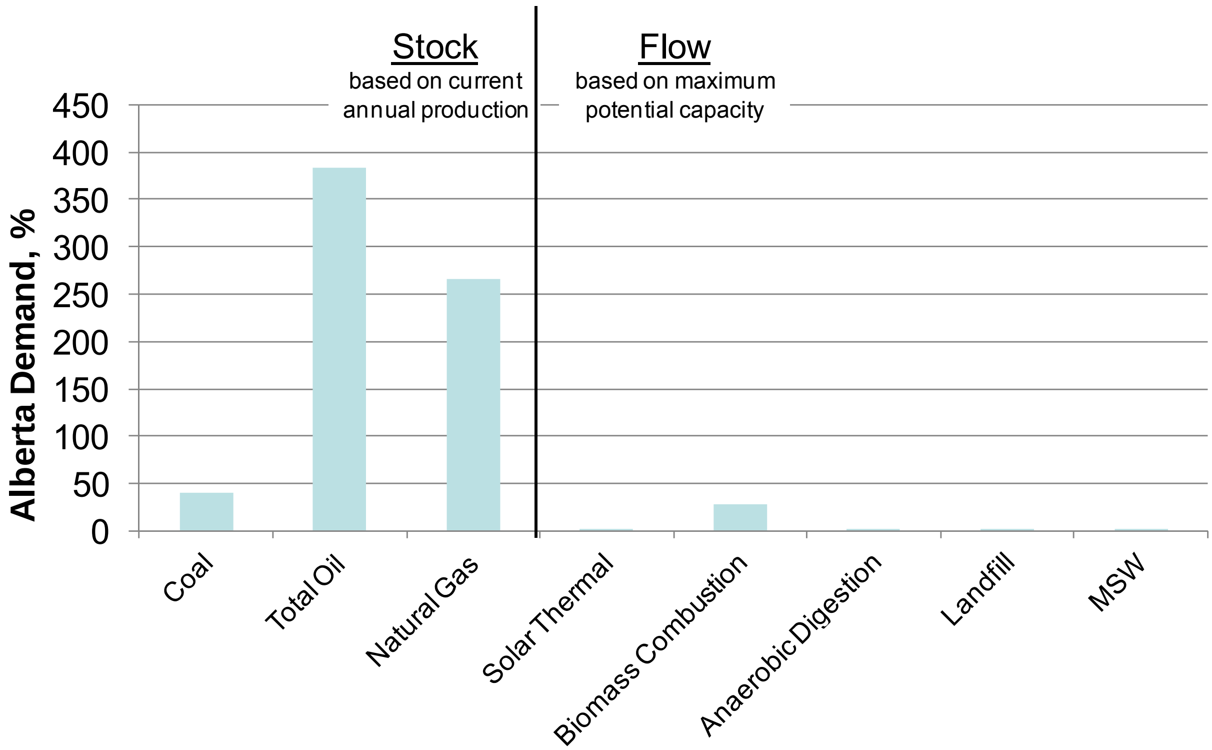


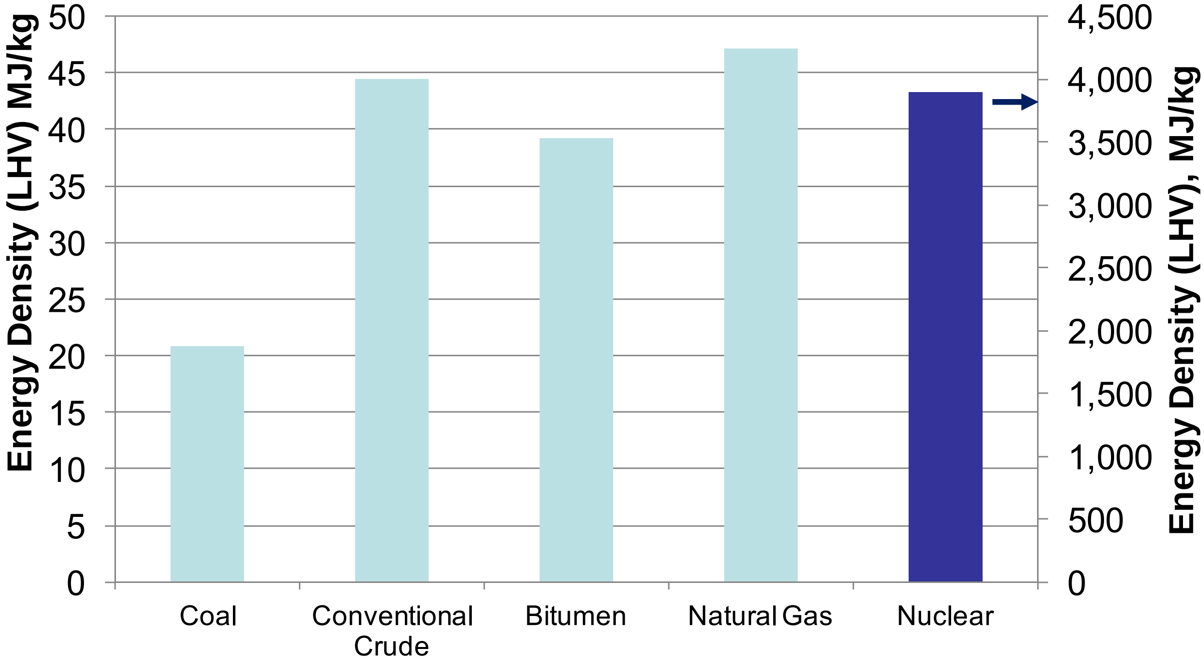
Figure 6.11.
Percent of Alberta Heat Demand if all of the Resource is Converted to Heat



Energy Density

Figure 6.12 shows the energy density of Alberta resources. As is well understood, oil and gas resources have higher energy density than coal. Uranium energy density is based on 3.2 wt% uranium in the fuel. We have chosen energy density of the uranium fuel as the basis for comparison instead of energy density of the ore because the energy density of the ore can vary widely. The value for nuclear energy is read from the right hand side of the graph as uranium fuel has a much higher energy density than other resources shown in Figure 6.12.

Figure 6.12.
Energy Density of Resources



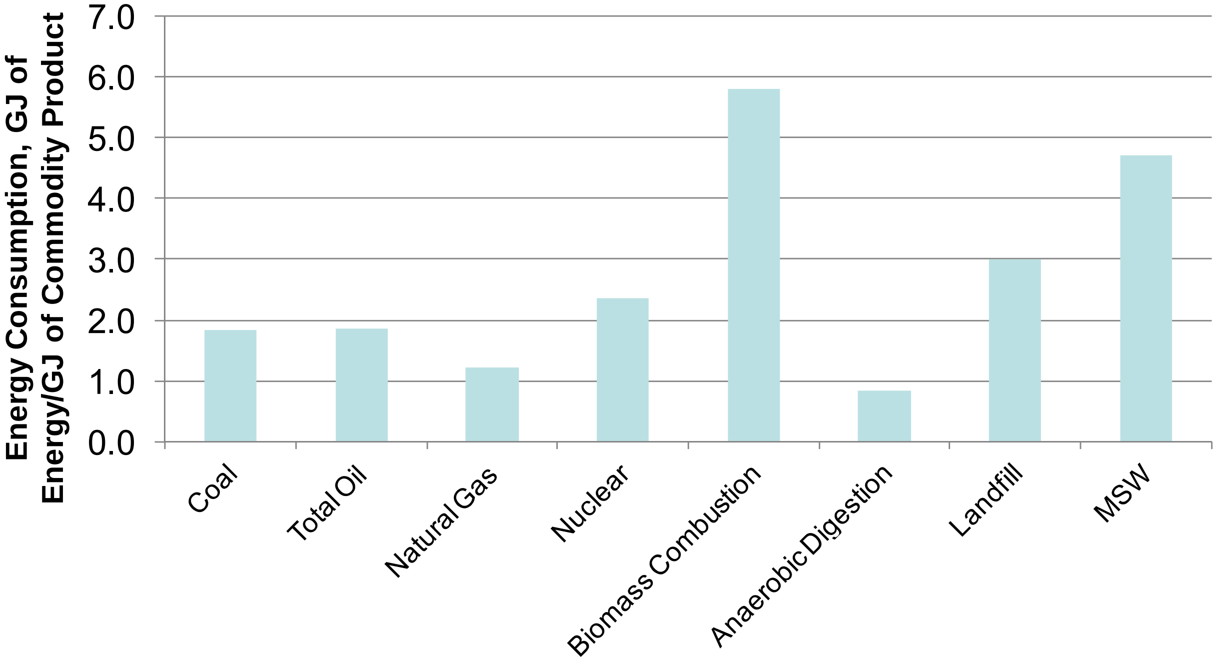
Efficiency and Energy Consumption

Two other key metrics are the efficiency of converting the primary resource to the commodity energy and how much energy is consumed in doing so.

Energy Consumption – Electricity Production

Figure 6.13 shows the energy consumed to make electricity. Energy consumption is based on pathways discussed in each resource/pathway section. All pathways are based on the use of steam turbines to create electricity. Biomass combustion and anaerobic digestion have relatively lower energy consumption as there is little energy expended in collecting or treating the on-site raw material before combustion.

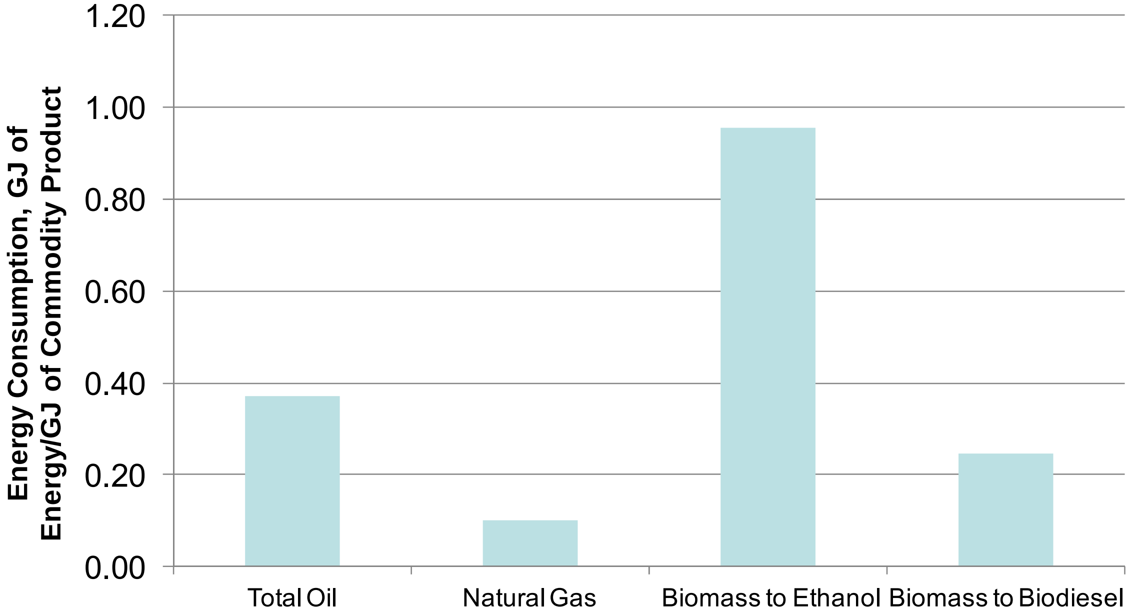
Figure 6.13.
Energy Consumption Electrical Production



Energy Consumption — Transportation Fuels

Figure 6.14 shows the energy consumed to make transportation fuels. The energy consumption for biofuels includes energy inputs in the crop production and processing as well as the manufacture of the fuel. It is most efficient to make transportation fuels from natural gas and least efficient to make ethanol from biomass.

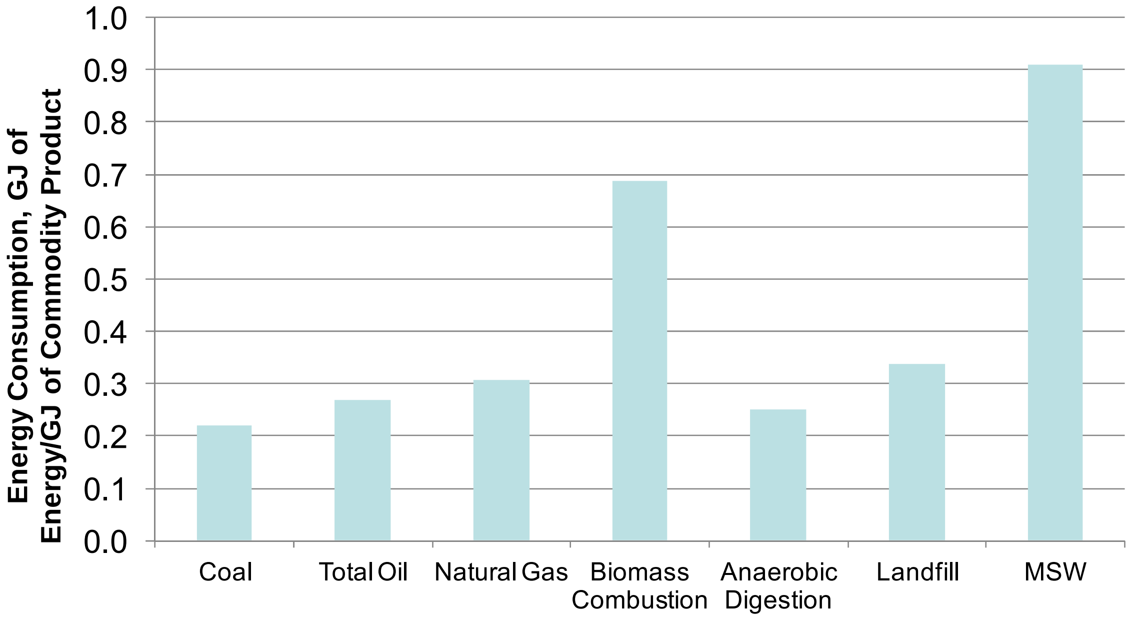
Figure 6.14.
Energy Consumption to Make Transportation Fuels



Energy Consumption – Heat

Figure 6.15 shows the energy consumed to produce heat from the commodity energy sources.

Figure 6.15.
Energy Consumption to Make Heat



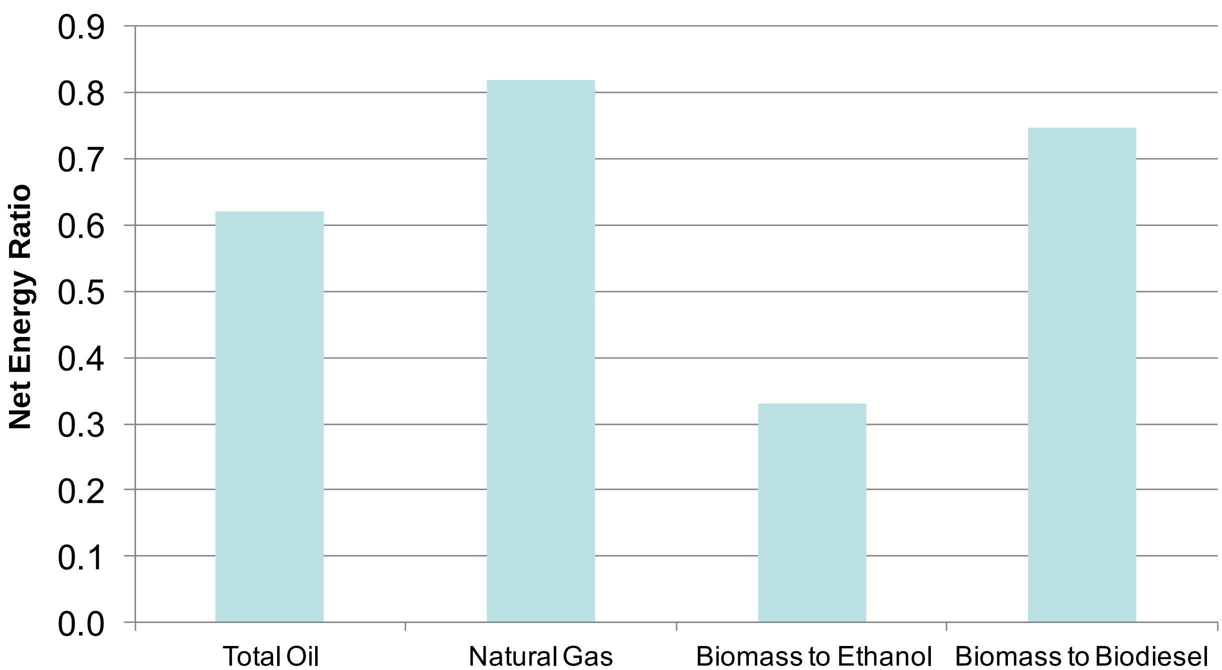
Net Energy Ratio

The net energy ratio is the ratio of the energy in the commodity divided by the (energy to convert the primary source to the commodity + energy in the primary source). This metric helps us understand the efficiency of conversion of the resource into the commodity. The higher the value of the net energy ratio, the greater is the efficiency of the conversion process. Energy to convert the primary source to the commodity includes energy lost in the conversion due to efficiency losses and also includes external energy inputs.

Net Energy Ratio — Transportation Fuels

The net energy to produce transportation fuels is shown in Figure 6.16.

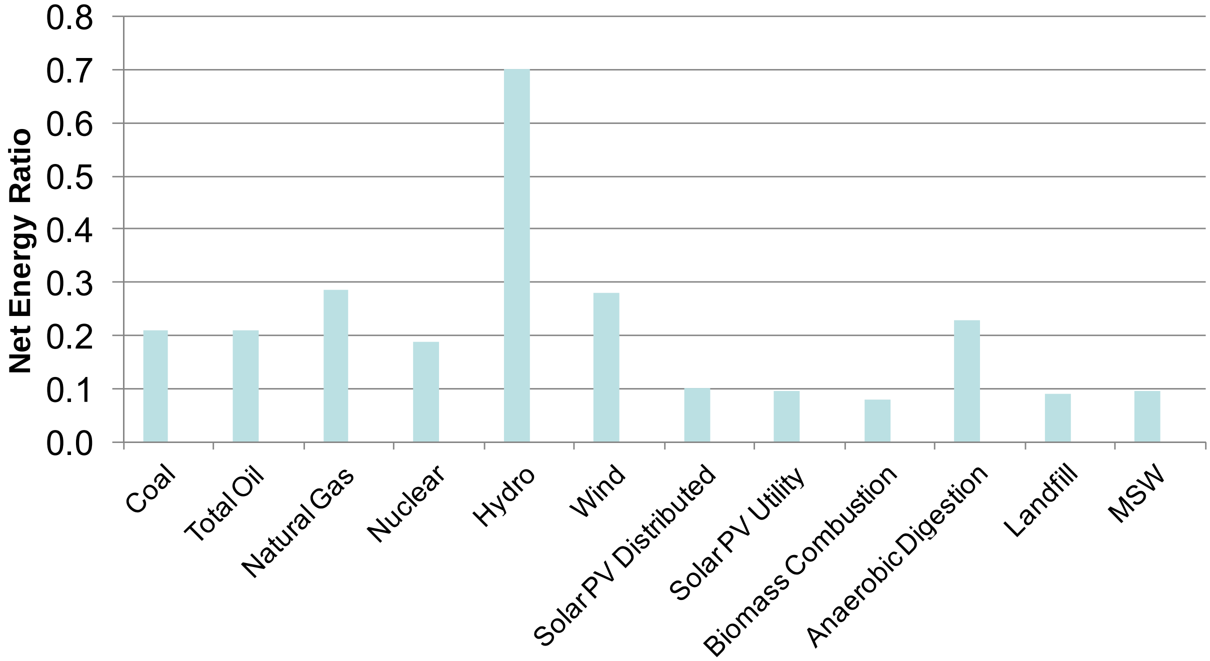
Figure 6.16.
Net Energy Ratio Transportation Fuels



Net Energy Ratio — Electricity

Figure 6.17 shows the efficiency to generate electricity from the different primary energy sources. The results show that hydropower is a highly efficient means to generate electricity.

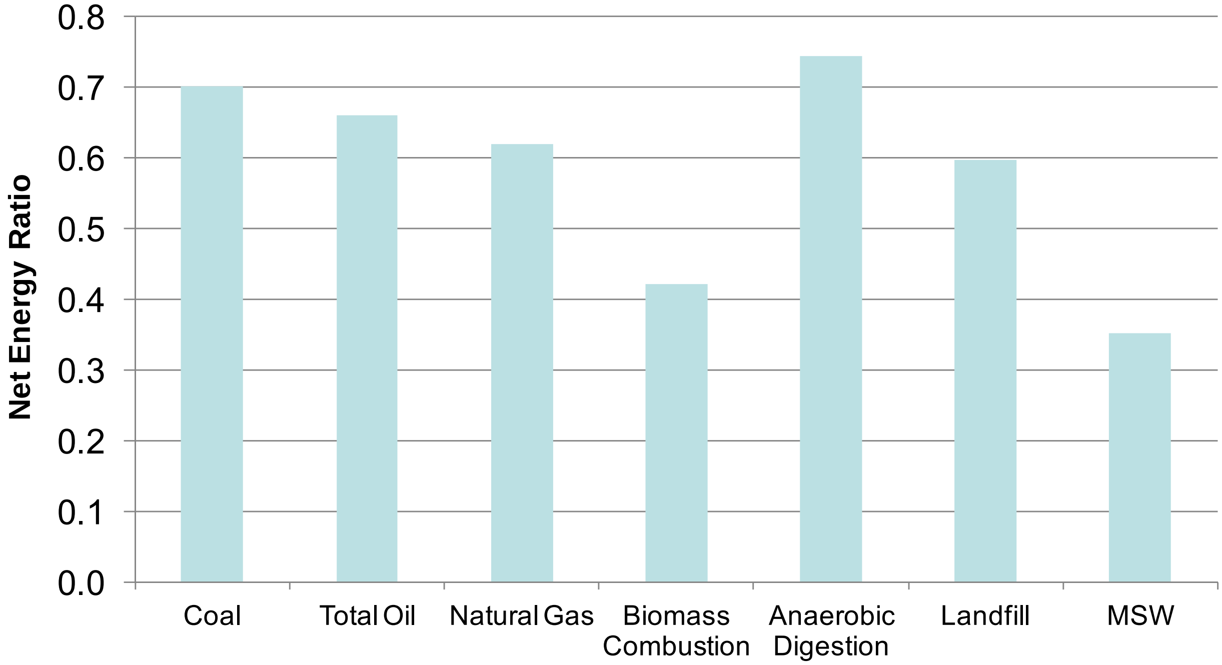
Figure6.17.
Net Energy Ratio for Electricity



Net Energy Ratio – Heat

The net energy ratio for heat does not vary substantially as the pathways to make heat are very similar. The pathways differ by only the energy to gather and process the resource to be able to feed the resource to a boiler. The net energy ratio for heat is shown in Figure 6.18.

Figure 6.18.
Net Energy Ratio Heat



Distance Delivered From Energy Sources

This metric enables us to compare energy as delivered to a vehicle from different primary sources. We have chosen to use three types of personal use vehicles to simplify the comparison of energy sources: a spark ignition engine VW Golf is used to evaluate bioethanol, gasoline and natural gas; a compression ignition engine VW Golf is used for diesel and biodiesel; the Nissan Leaf, a plug in electric vehicle – with no backup from an internal combustion engine - is used to evaluate electricity generated from the different primary sources. For energy sources such as oil and bitumen which produce both gasoline and diesel, the distance reported is a blend based on gasoline and diesel yield from oil and bitumen and the distance achieved by each fuel evaluated in the appropriate vehicle.

Figure 6.19 shows the distance that can be delivered per GJ of primary energy converted to transport fuels. Most of these fuels are liquid, with the exception of natural gas, which is assumed to be compressed for use on board the vehicle. Figure 6.20 shows the distance that can be delivered if the primary energy is converted to electricity.

Figure 6.19.
Distance Delivered from Converting Primary Energy to Liquid Fuels and Compressed Natural Gas

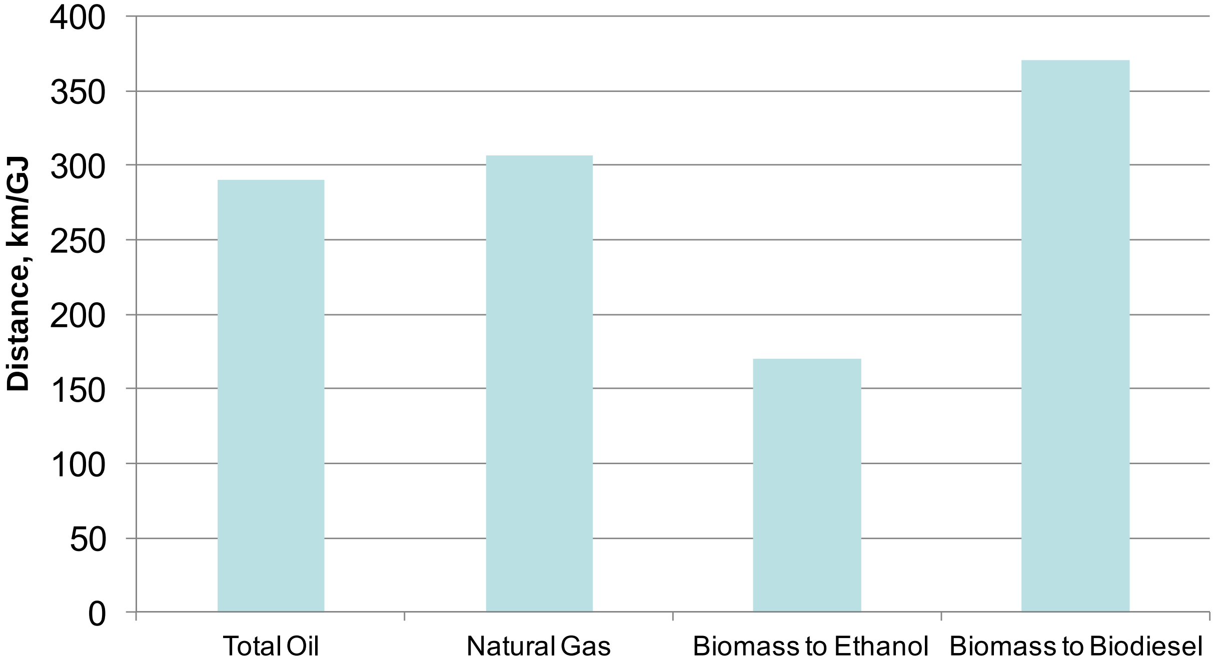
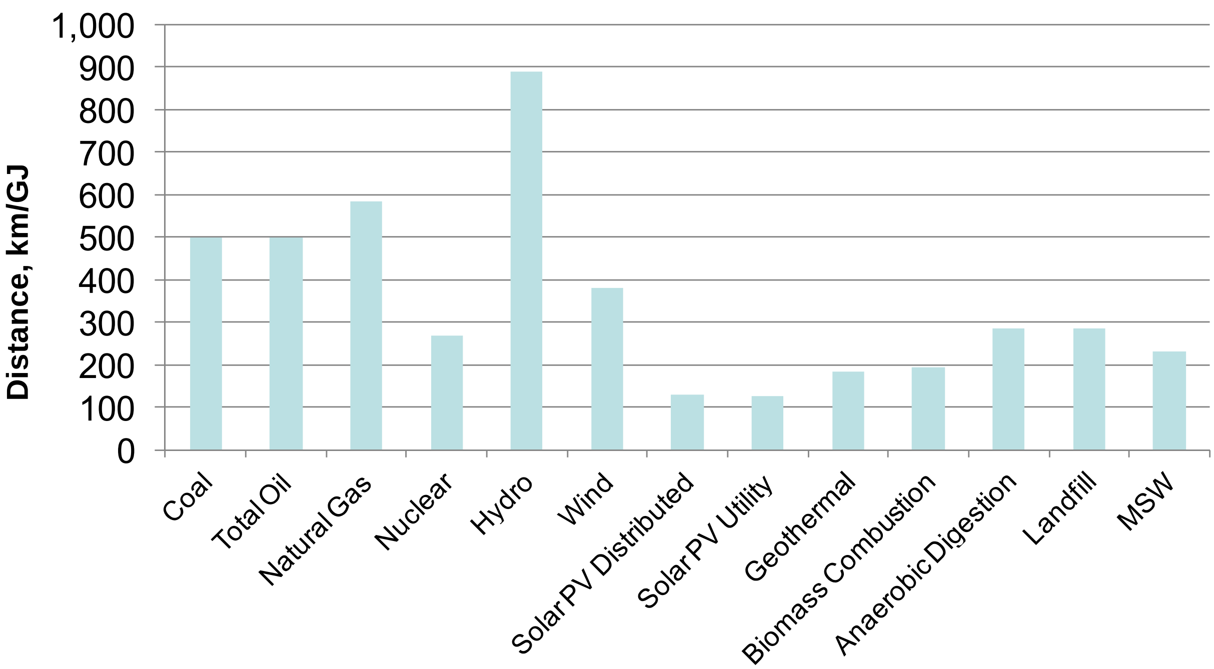


Figure 6.20.
Distance Delivered from Converting Primary Energy to Electricity



Environmental Metrics Comparison

Energy sources also were compared on the basis of environmental metrics. These metrics include GHG emissions from fuel production through consumption, as well as land use and water use in producing the commodity energy.

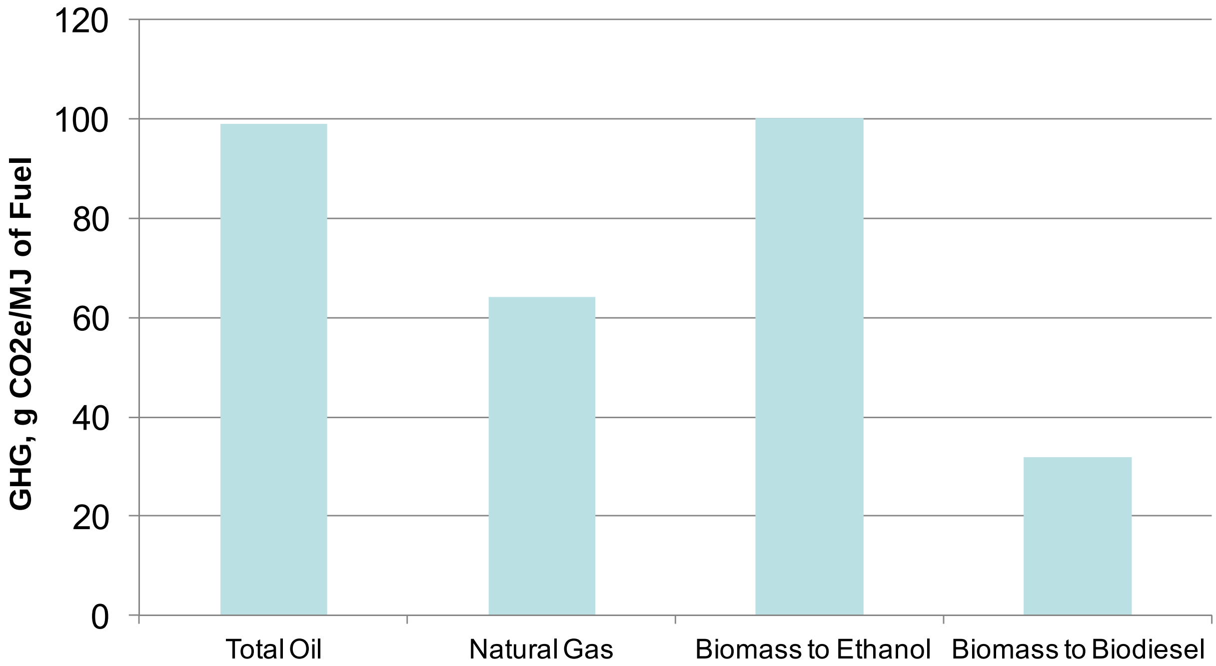
GHG Emissions

GHG emissions were estimated for producing transportation fuels, electricity and heat from the primary energy sources.

GHG — Transportation Fuels

Figure 6.21 shows the GHG emissions from producing the primary energy source, transporting it, converting to a transportation fuel and then consuming the fuel onboard the vehicle. Gasoline and diesel from bitumen and ethanol from biomass have the highest estimated GHG emissions from production of the primary energy resource to consumption of the primary energy product.

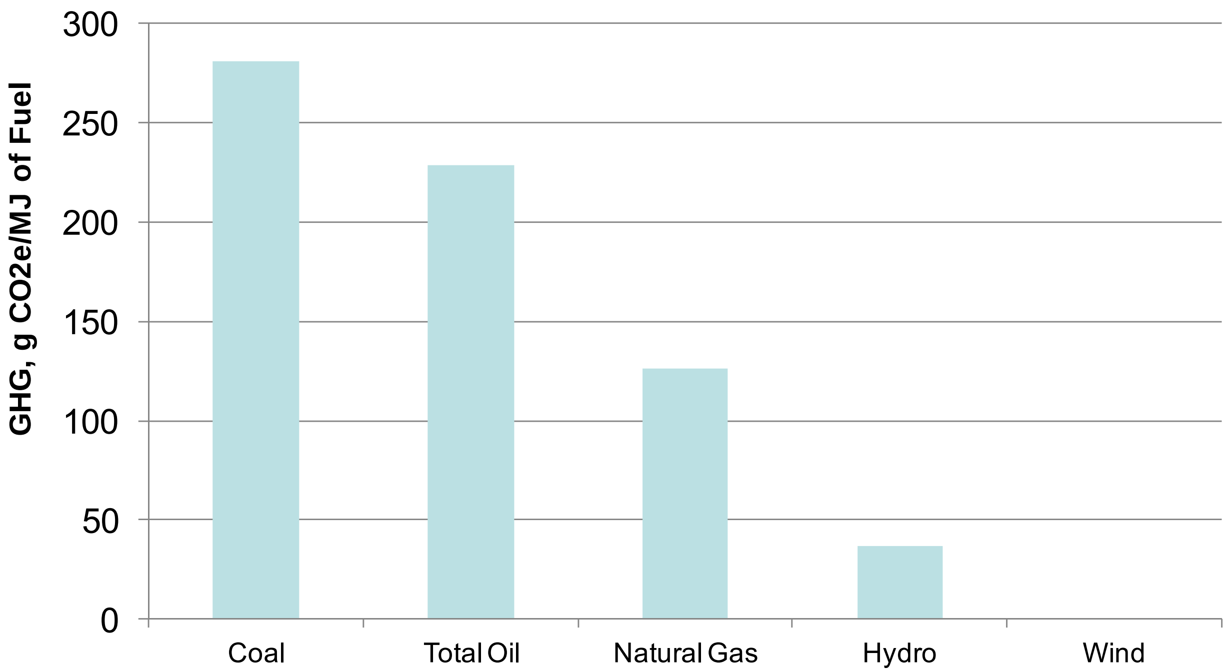
Figure 6.21.
GHG Emissions from Converting Primary Energy to Transportation Fuels



GHG — Electricity

Figure 6.22 shows the estimated GHG emissions for converting the primary energy source to electricity. Coal has the highest GHG emissions from production of the primary resource to delivery of electricity at city gate. Wind has no GHG emissions associated with it by the methodology we used in the evaluation. Biomass produces no net GHG for electric power generation.

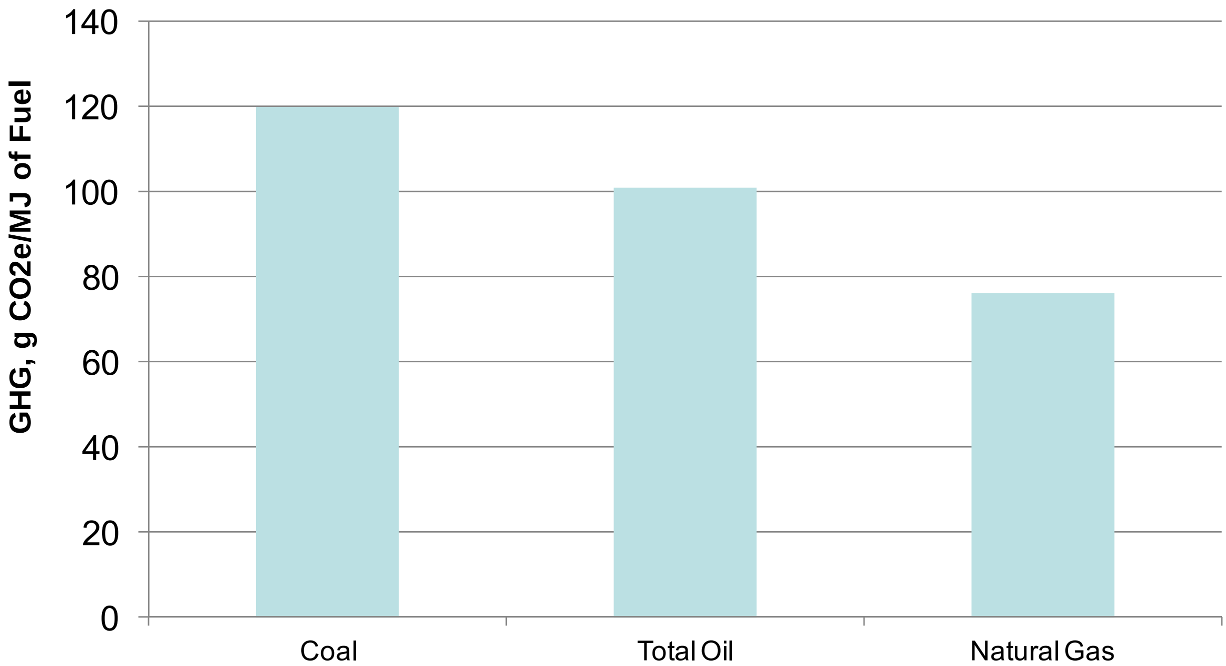
Figure 6.22.
GHG Emissions from Converting Primary Energy to Electricity



GHG — Heat

Figure 6.23 shows the GHG emissions from generating heat from the primary energy. Biomass combustion produces no net GHG.

Figure 6.23.
GHG Emissions from Converting Primary Energy to Heat



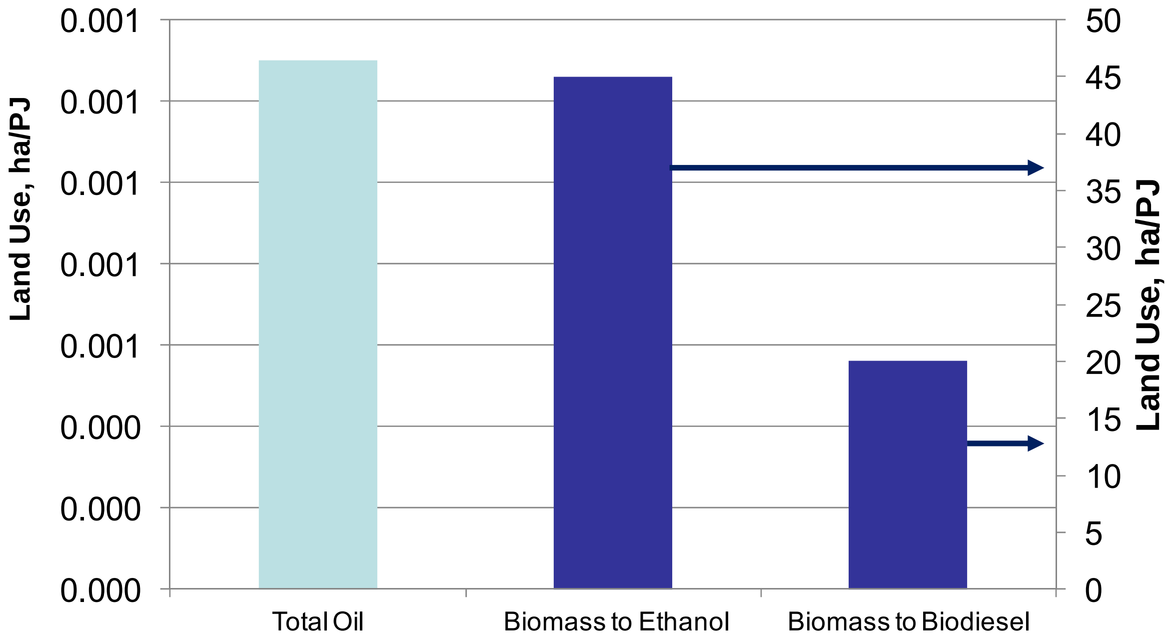
Land Use

Land used in producing the primary energy sources is another important environmental metric. It is a measure of the land-based energy density of the primary source and gives an indication of how much land is needed to generate the commodity energy from the primary energy source.

Land Use — Transportation Fuels

Figure 6.24 shows the land use to make transportation fuels. Biomass to ethanol and biomass to diesel fuel should be read from the right hand axis. Oil (combined conventional, mined and in situ bitumen) should be read from the left axis in Figure 6.24. Land use is highest for biofuels as a result of the land required to grow the resource and the relatively low energy density of crops. In contrast, hydrocarbons, even mined bitumen, have smaller land footprints relative to the energy that is produced.

Figure 6.24.
Land Use Transportation Fuels



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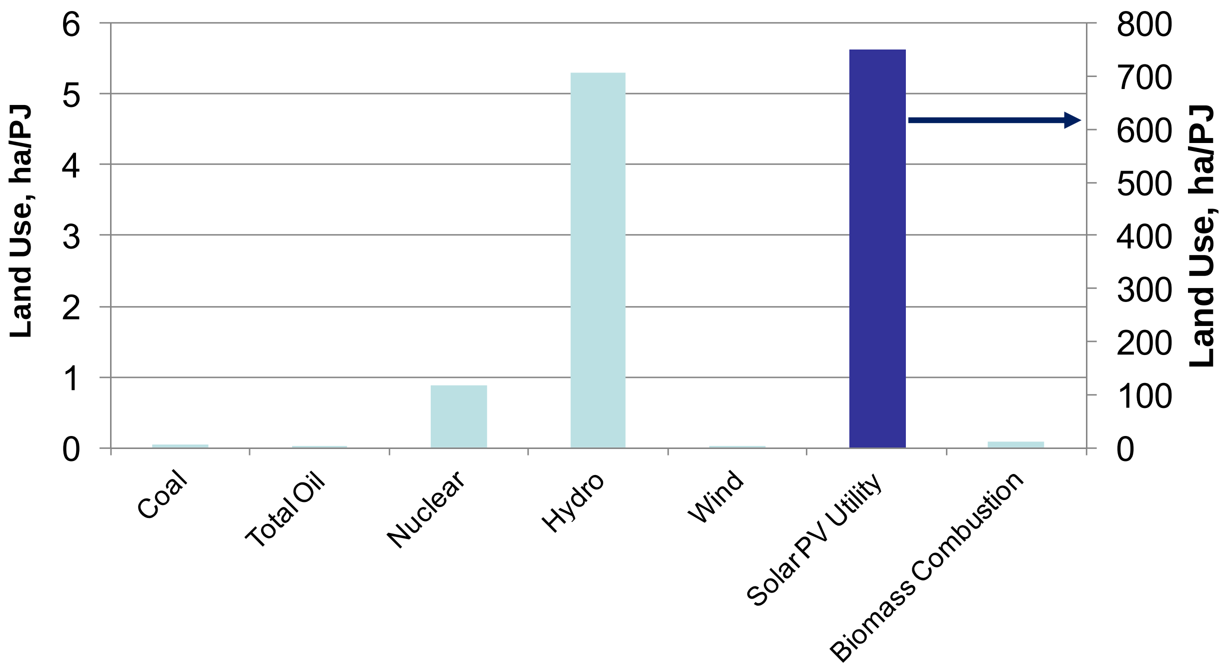
Land Use— Electricity

Land use for electricity generation is shown in Figure 6.25. Utility Solar PV should be read from the right hand axis; the other energy sources from the left hand axis. Utility Solar PV assumes that the solar panels will be set up in an array on land, not on building roofs (as is the practice for distributed solar PV). As a result of the relatively low energy density of electricity from solar PV, the land use is high for this resource. The high energy density of coal, crude oil, and bitumen result in low land use, despite in some cases the use of mining to extract the resource. Land use for nuclear is based on the default enrichment mix and a weighted average of land use in mining. Hydropower is high relative to hydrocarbon resources since the land disturbance by dams is high.

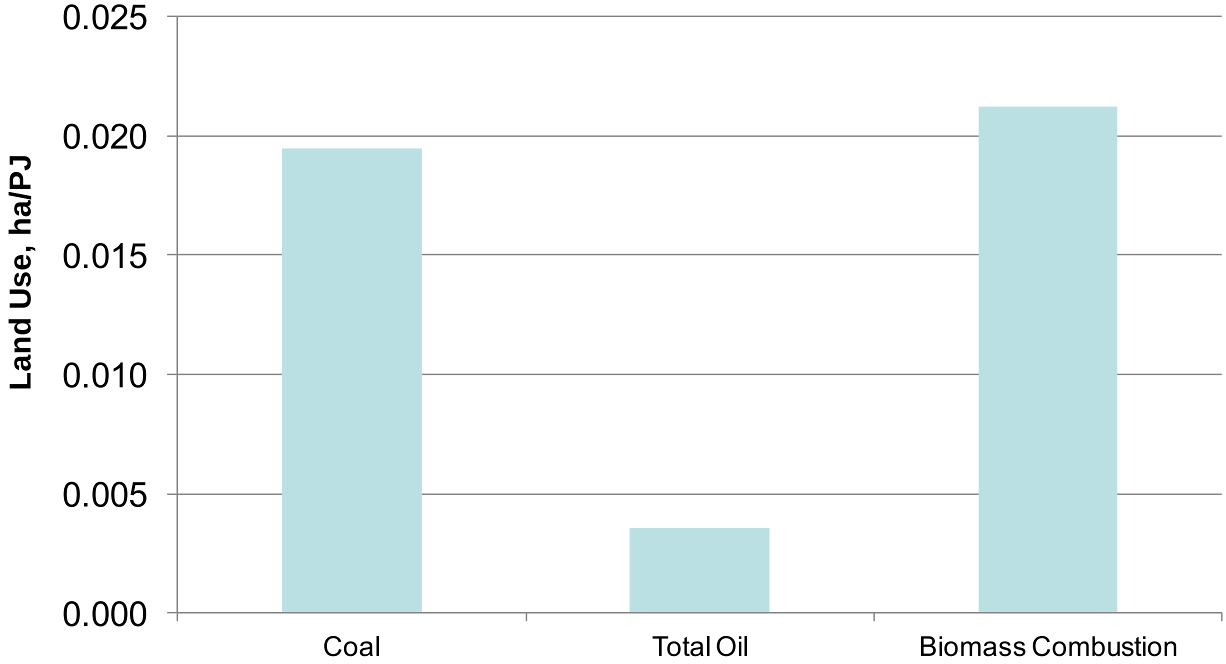
Figure 6.25.
Land Use Electricity



Land Use — Heat

Land use associated with production of primary energy sources for the generation of heat is small, as shown in Figure 6.26.

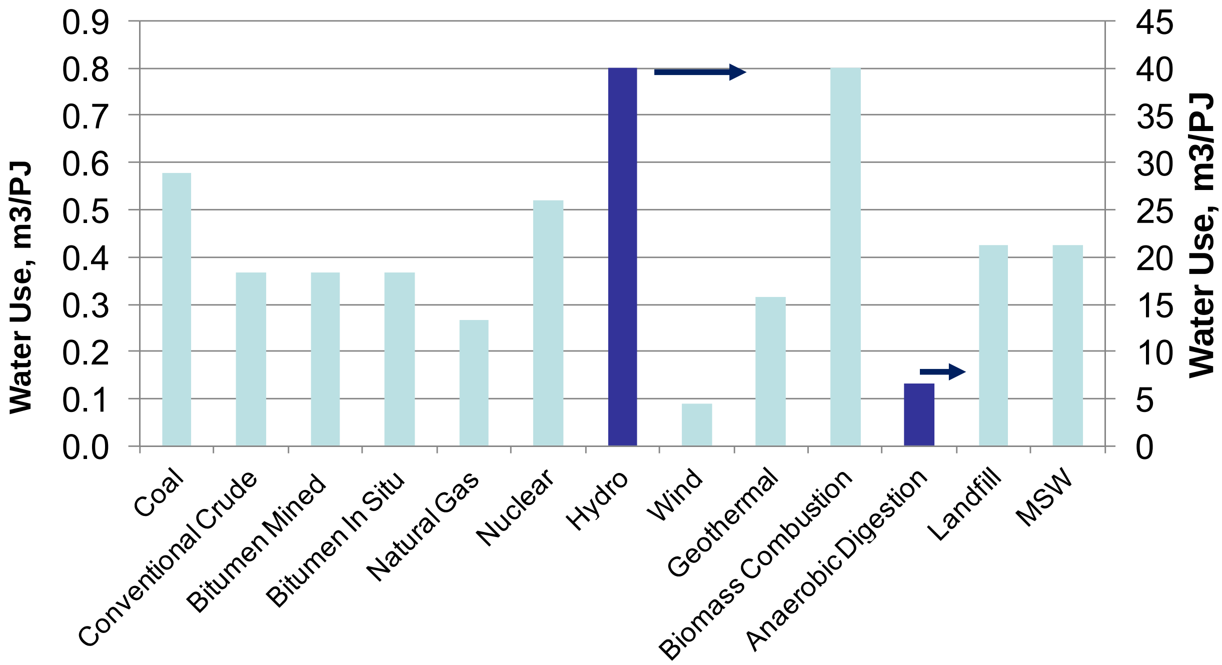
Figure 6.26.
Land Use –Heat



Water Use

Water use for electricity generation is shown in Figure 6.27. Water use is small for all resources except hydro (evaporation), which should be read from the right hand axis.

Figure 6.27.
Water Use Electricity Generation



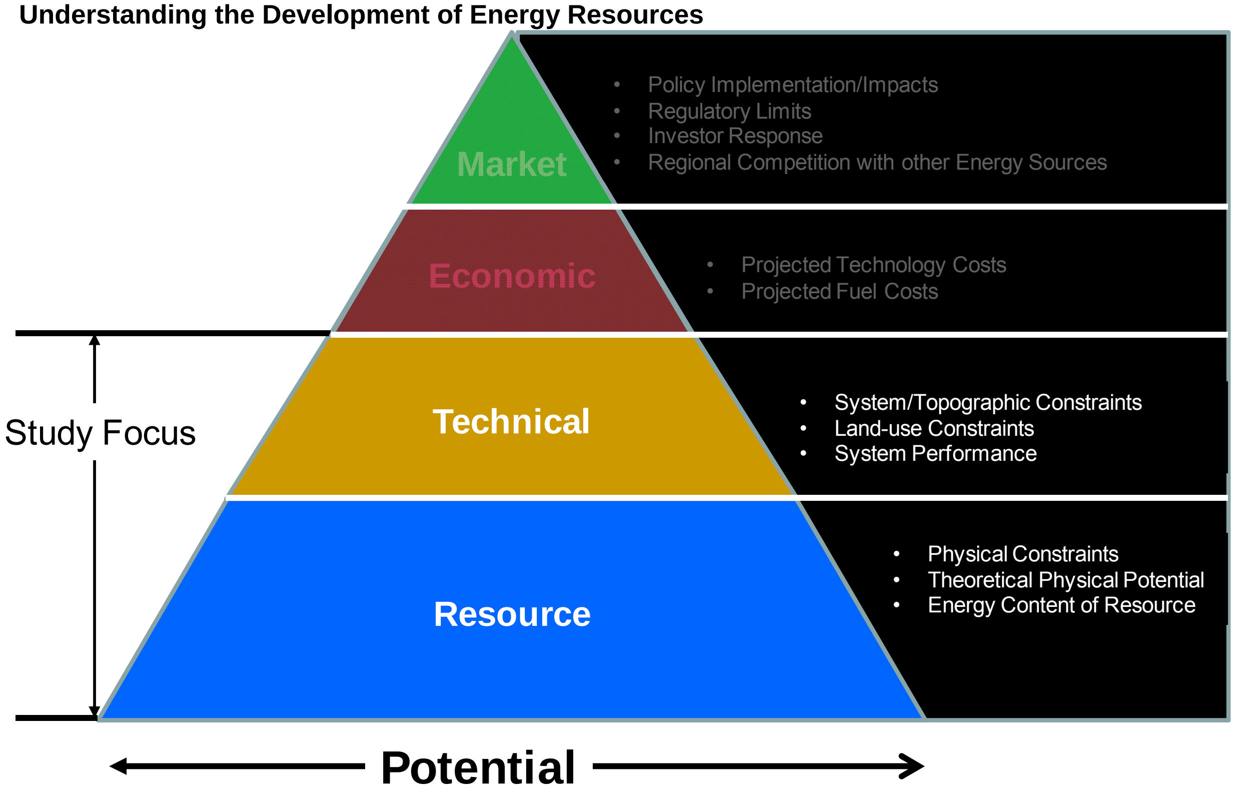
Section 7

Looking Forward

Looking Forward – Future Scenarios

Figure 7.1 reminds us that the focus of the Study is on energy resource potential and the technical issues associated with the potential development of Alberta's primary energy resources. As we consider future scenarios, we remain focused on energy resources and technology feasibility and development issues, not supply-demand forecasts or economic analyses of energy resource development choices. We discuss going beyond the Energy Potential and Metrics Study in Section 8, "Conclusions and Next Steps."

Figure 7.1
Understanding the Development of Energy Resources



Source: National Renewable Energy Laboratory (NREL), 2012

We have discussed future scenarios for pathways and metrics for each primary energy source in earlier sections of the report. Here we have abstracted the major points from these discussions to provide an overall view of major potential developments to energy resources in Alberta. We have grouped the future scenarios into two categories:

- **Incremental Technology Development -** Technology developments that are incremental in nature and are based on R&D efforts that are currently underway and are anticipated to be commercialized in the short term. An example would be efforts to improve currently available enzymes and yeasts to increase bioethanol yields and processing efficiencies.

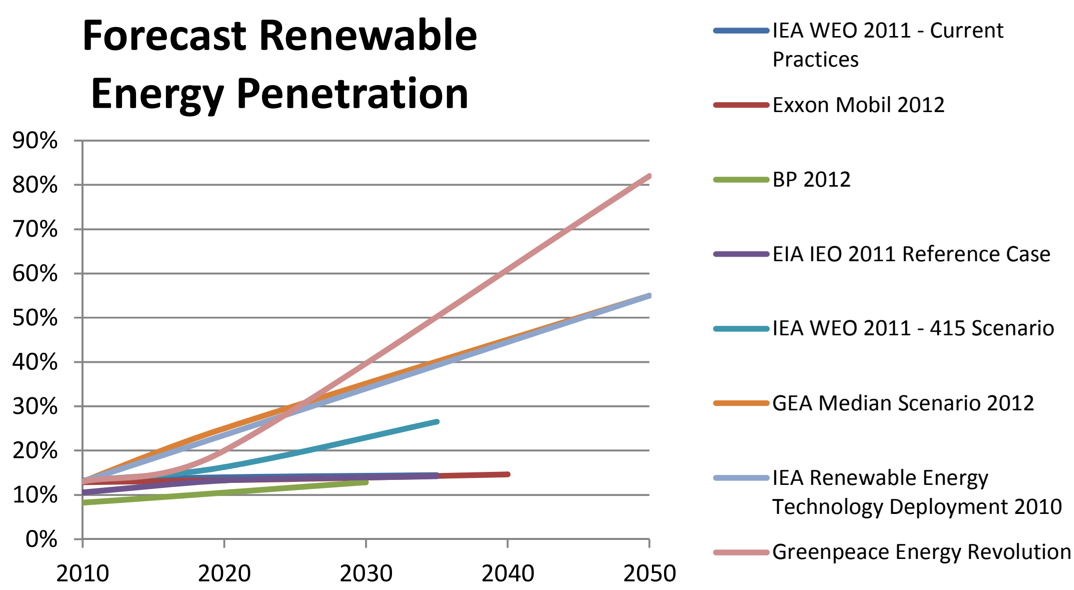
- **Breakthrough Technology Development -** R&D that is focused on elements of the resource pathways that represent the largest barrier to more extensive technology deployment and are expected to be commercialized within a medium term (20 year) time horizon. An example would be an entirely new class of enzymes could enable cellulosic ethanol commercialization on a broad scale.

The rate of deployment of new technologies is dependent on investments in technology development. New technologies as described in Section 5, are often at different stages in the technology development and maturation path, and have different learning and commercialization rates. Technologies move along the path to commercialization by learning improvements that are developed as new capacity is built.

The outcome of the learning process is an improved technology that is more able to meet market needs which in turn enables more capacity to be built. Eventually, for successful technologies, the technology will move along the technology development path to the point where the technology is able to compete without the need for additional support in the market. These supports can include not only corporate investment in R&D but also support from regulations, performance standards, or taxes and tariffs.

How new technologies will be implemented in the future is difficult to predict. To show the diversity of view on technology implementation, we looked at existing forecasts from a number of different sources to see if there is a consensus view regarding the deployment of new technologies in the energy field. As we see in Figure 7.2, there is little consensus on the extent of renewable energy penetration. The basis for these forecasts depends on assumptions regarding economic and policy developments in the energy field and the extent and rate of technology development. The forecasts also reflect the point of view of the organization constructing the forecast.

Figure 7.2
Forecast Renewable Energy Penetration



The scenarios in Figure 7.2 are from the following sources:

- IEA WEO 2011 Current Practices
- IEA WEO 2011 415 Scenario – what energy deployment might look like in order to stabilize atmospheric CO2 concentration to 415 ppm
- IEA Renewable Energy Technology Deployment 2012 (International Energy Agency)
- BP 2012 (BP, 2013)
- Exxon Mobil 2013 Outlook for Energy A View to 2040 (ExxonMobil, 2012)
- Greenpeace Energy [R]evolution 2012, (Greenpeace)
- EIA IEO 2011 (Energy Information Administration, 2011)
- Global Energy Analysis (GEA) Median Scenario 2012 (International Institute for Applied Systems Analysis, 2012)

Trends in New Technology Development

Technology developments are taking place to improve technologies that are pathway specific, that is, technologies that directly affect how resources are processed into energy commodities, and in ways that are outside the pathways. Technologies that are outside the pathways are technologies that affect how energy commodities are used and the demand for energy commodities.

Pathway Related Developments

For fossil fuels, many extraction and production technologies are mature and, for the most part, technology developments are incremental in nature. In particular, we have observed that developments tend to be focused on efficiency improvements and on reducing environmental impacts such as:

- Efforts to improve efficiency and energy use to reduce GHG emissions
- Reducing environmental impacts, e.g., tailings pond management in oil sands processing
- Reducing water use, e.g., improving steam-to-oil ratios for in situ bitumen extraction and bitumen mining, and increased water recycle in bitumen operations

Technology developments also are engaged in modifying existing technology to fit changing energy needs, such as:

- Small scale nuclear reactors
- Modifying in situ properties of bitumen without the need for heat
- Partial upgrading of bitumen to reduce the need for diluent in transport

Finally, efforts are being undertaken to reduce costs, especially the costs of breakthrough technologies such as carbon capture and sequestration.

Renewable energy resources are undergoing incremental developments to reduce cost and improve efficiencies, such as:

- Reduction in cost of components for solar PV, in particular for the balance of system components and the increase in energy density of solar panels
- Higher and bigger wind turbines
- Improved manufacturing techniques for solar PV and wind turbines

Although many renewable technologies have lower environmental impacts, there are certain environmental metrics that show renewable technologies to have relative weaknesses.

Technology developments to improve environmental impacts may be seen in:

- Micro and run of river hydro
- Solar PV manufacturing techniques and increased recycling efforts

There also are many opportunities for breakthrough technologies in areas such as:

- Geothermal mapping technologies
- New heat transfer media for geothermal heat
- Cellulosic biofuels
- Novel solar PV materials

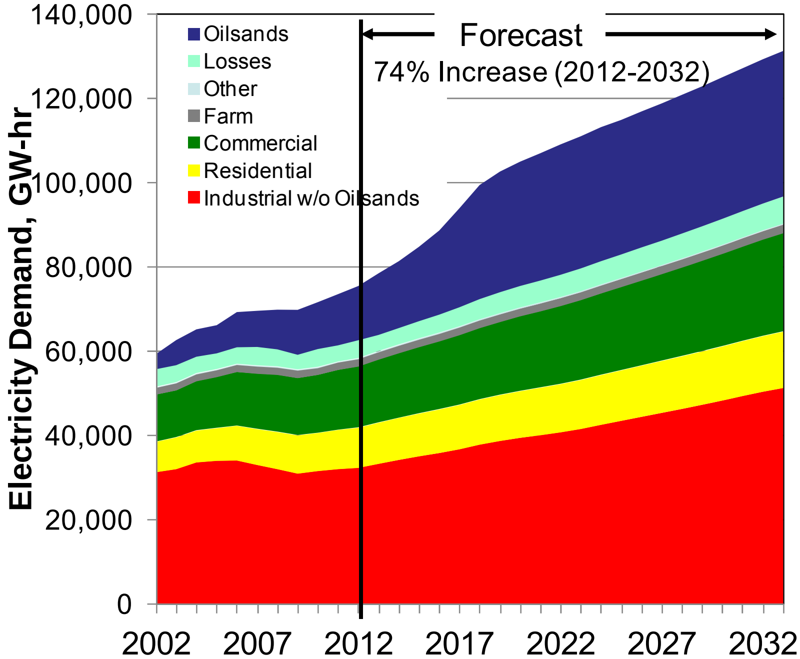
Distributed versus Large Scale Power Generation

New technology developments that may affect how commodities are used include distributed energy technologies, which include distributed solar photovoltaics, solar thermal, geothermal heat, and small scale run of river hydro. The nature of distributed power enables the user to have more control over power generation, reduces lines losses in electrical power distribution and can save capital costs in remote areas by reducing electrical power grid requirements.

In the case of geothermal heat, solar thermal and solar photovoltaics, distributed generation reduces losses in transmission to enable higher efficiencies. However, it will be more difficult to make use of these distributed energy processes in industrial applications such as cement kilns or oil sands applications because of the intensity and quantity of power required by these markets. Therefore in a highly industrialized economy such as Alberta's the overall penetration of distributed power generation may be limited because the portion of the market that can effectively use this type of power generation is a relatively small relative to overall power demand.

As shown in Figure 7.3, residential, commercial and farm demand is forecast to be a relatively minor portion of the overall electricity demand as compared to oils sands and industrial demand. The oil sands and industrial electricity market demand which is more likely to be met with power from large scale thermal power plants or cogeneration plants on site.

Figure 7.3
Forecast Alberta Electricity Demand



New Technology Developments in Demand Management and Reduction

Outside of the pathways that transform resources to energy commodities, the energy market and energy delivery systems are changing in response to shifting demand patterns and new regulations. Technology developments are focusing on demand management, demand reduction and enabling higher levels of distributed technologies

Electricity: Technology providers are finding ways to decrease energy demand and to manage demand through:

- Efficiency improvements such as the implementation of LED lighting and low energy use appliances for residential use
- Changes in building environments to include more daylighting of offices and homes to reduce lighting demands
- Demand-side control systems to enable load leveling and more efficient operation of thermal power plants

- Improved forecasting and planning tools for wind and solar which together may enable greater use of intermittent resources
- Smart grids with reduced power line losses, and the ability to manage more distributed generation sources and more variable generation sources
- Cost effective power storage to increase the level of renewable power that would be delivered to the grid while reducing compromises to grid performance. Storage technologies currently under development include batteries, thermal and mechanical storage, and chemical storage.

Transportation Fuels: Reduced demand for transportation fuels is occurring both from a miles-driven standpoint and through the increase in vehicle mileage standards. In Canada, from 2005 – 2011, the sales-weighted on-road fuel efficiency for new gasoline fueled automobiles has improved from 9.2 litres/100 km to 8.5 litres/100 km and the sales-weighted on-road fuel efficiency for new gasoline light trucks has improved from 13.2 litres/100 km to 11.7 litres/100 km. (Environment Canada, 2013).

- Demographic trends such as the increased urbanization of the population, increasing average age (older people drive less) and increased telecommuting trends decrease miles driven per capita
- Implementation of regulations for increasing mileage standards for heavy duty trucks (Gazette, SOR/2013-24 February 22, 2013, Heavy-duty Vehicle and Engine Greenhouse Gas Emission Regulations, 2013)
- Proposed regulations in Canada for increasing mileage standard for passenger automobiles and light duty trucks in conjunction with the US EPA such that vehicle mileage standards will increase on an annual basis from 2017 – 2025.
- Increasing market penetration of hybrid and electric cars will decrease transportation fuel demand

Heat: New and improving technologies such as solar thermal and geothermal heating and cooling are enabling increasing amounts of distributed energy supplied as heat. Heat storage technologies such as the heat storage complex at the Drake Landing, Okotoks development is an example of how sophisticated solar thermal storage technology can improve the storage and delivery of solar thermal heat. Improvements in building construction such as energy efficient windows, high-R insulation and radiant floor heat reduce residential heat demand intensity.

In industrial applications, demand for heat is being managed by improving construction methods to decrease heat loss and through increased heat integration in process units.

Trade-offs

This analysis has focused on defining the metrics for each resource and pathway as a means to define the energy demand, efficiencies and environmental impacts of each primary energy pathway to commodity energy production. The analysis provides a picture of a diversified energy portfolio for Alberta with each piece of the portfolio providing energy commodities in ways that provide balance to the overall portfolio.

As energy commodity supply in Alberta changes to meet market needs and to meet regulatory demands, we see that the energy portfolio will shift to meet these new needs and demands and that this shift will be informed by the trade-offs among the energy commodity supply pathways. For example, federal regulatory policy has dictated that Alberta reduce electrical power generation from coal unless CCS is implemented. The response to this regulatory change is unlikely to be a wholesale change from coal fired power plants to another form of power supply such as wind or nuclear. Instead we can foresee a portfolio approach to energy supply that embodies the tradeoffs that are quantified in the metrics analysis. The new electrical power supply could more likely be a mix of wind, distributed solar photovoltaics, and natural gas that will provide an acceptable level of carbon emissions balanced by the need to provide a non-intermittent supply of electricity to users connected to the grid.

Section 8.

Conclusions and Next Steps

Conclusions

The report includes a comprehensive view of all major energy resources in Alberta and the pathways that are used to create basic energy commodities used in Alberta; namely, heat, electricity and transportation fuels. We have used a broad spectrum of metrics to enable the reader to understand energy availability, energy density, and the environmental impact of a wide range of energy resources and pathways in Alberta.

The use of metrics is important because no single parameter defines an ideal energy resource. Each energy resource requires an assessment of the total amount that is available, the potential to produce useable energy from the resource, and the impact of converting the primary resource into a commodity energy product. Assessment of energy resources involves using a number of different metrics, some of which may be more relevant to some resources than to others. By using a wide range of metrics in our assessment we have attempted to present a balanced view of the diversity of energy resources that could be available to meet the commodity energy demand in Alberta. The challenge in applying these metrics was to appropriately define them and establish proper boundaries for metrics assessment.

Metrics

The following overall conclusions can be drawn from the metrics developed in the Study. Not all metrics are listed. Further detail on metrics not shown is in Section 5.

Production and Capacity Metrics

1. **Remaining established reserve potential, primary source** – measures how much of the primary energy is available in reserve. It applies to stock energy sources such as coal, oil, natural gas but does not apply to flow resources such as wind, solar, or biomass.

   Alberta has abundant established reserves of bitumen and coal, much less of natural gas. However, the estimate of established reserve potential does not include unconventional oil and gas from coal bed methane, tight oil and gas and shale oil and gas. These unconventional resources have not yet been developed to the point where established reserves can be quantified. Based on geological observations and exploration to date there are indications of substantial unconventional resources to be developed in Alberta which would add to Alberta's established oil and gas endowment.

2. **Actual annual production, primary source** – measures how much of each primary source is produced in Alberta. It is an important benchmark for evaluating alternative

sources of energy. (In the Study, production rates for stock based energy sources were kept at current rates and not increased.)

Alberta produces more natural gas than any other energy resource. Alberta produces over 73% of Canada's marketable natural gas supply, 61-62% of the Canadian crude oil supply, and 42% of the Canadian coal.

4. **Current actual commodity produced and as a percent of Alberta consumption –** measures how much of each commodity energy (electricity, transport, and heat) is produced relative to Alberta's current demand. Surplus commodity energy can be exported.

   Alberta produces nearly 150% of its commodity energy demand for transportation fuels; what is not used in Alberta is exported to the other Canadian provinces and the US. Alberta produces nearly all of its electricity and all of its heat commodity energy.

   Electricity - Although capacity exists in Alberta to generate electricity from energy resources such as distributed solar photovoltaic, anaerobic digestion, and landfill gas, the amount of electrical generation capacity that these resources currently represent is small compared to the generation capacity from coal and natural gas. Electricity generation is dominated by coal in Alberta, with much of the rest of electricity from natural gas both from dedicated plants and as a byproduct of cogeneration of heat for oil sands energy extraction. Wind is a growing resource in Alberta but is still a small contributor.

   Transportation fuels - Transportation fuels are produced from crude oil, including bitumen. There is virtually no production of transportation fuels from non-oil sources in Alberta.

   Heat - Heat in Alberta is primarily produced from natural gas. Some of the natural gas based heat is for space heating but the majority of natural gas for heating is for high temperature heat for steam used in bitumen production, in bitumen upgrading, and refining. Some heat in Alberta is produced from biomass, some from waste streams from wood production, some from propane - mainly for residential heating, and there is a small amount of space heating from geothermal and distributed solar.

5. **Commodity production if all Alberta primary source is converted to commodity** – measures how much of each commodity energy could be produced if all the available primary energy were converted to the commodity energy. This metric assumes that if all of the primary energy source is used to produce commodity energy it is not available for other purposes, such as biomass for food, etc.

   Electricity – Over 700% of Alberta's current demand for electrical power could be generated from all the natural gas produced in Alberta. Nearly 800% of the electricity could be generated from the oil that is produced. About 700% of the electricity could be generated from wind if wind turbines were deployed over 25% of the potential land area in the white areas of the province with turbine spacing of 70 hectares per turbine. Installation of solar panels over all of the white space could supply many times the current demand for electrical power in Alberta – but this would mean that there would be no land for crop production. If solar farms were instead restricted to 10% of the white space, dedicated solar could easily supply ten times Alberta's electric power demand. However, because of the large summer-winter variation in daylight in Alberta, significant electrical storage and non-intermittent electricity generation backup would be needed for this option.

Transportation fuels - Almost 700% of Alberta's demand for transportation fuel could be supplied if all the bitumen and conventional crude oil produced in the province were converted to transportation fuels. More than 550% of Alberta's transportation fuel demand could be met by the current production of natural gas – though there would be no natural gas for other purposes, and some electrical energy would be consumed in compressing the gas for on-board vehicle storage. Biofuels potentially could supply approximately 40% of current demand, but only if all land in Alberta were converted to crops that can be converted to biofuels.

Heat – All of the natural gas produced in Alberta could supply more than 250% of Alberta's current demand for heat – but this would eliminate export of natural gas to other provinces and the US. All of the oil produced in Alberta could potentially supply about 400% of Alberta's heat demand; if all of the coal produced annually in Alberta were used for heat, it could supply 40% of Alberta's current heat requirements. Landfill gas, anaerobic digestion, biomass combustion and MSW could supply only a small percentage of Alberta's heat requirement.

Energy Density Metrics

8. **Primary Source Energy Density (LHV) -** measures the energy content per volume or weight of an energy source. Higher energy density is desirable for energy sources that must be stored on board vehicles, for example:
    - Coal has energy density of 14 to 21 MJ/kg depending on the coal type (rank)
    - Natural gas has energy density of 47 MJ/kg (37 MJ/standard m^3). Compressed natural gas is sold by weight and has a volumetric energy density about ten times higher than natural gas at standard pressure. Liquefied natural gas has an energy density of 21 MJ/l Oil has energy density typically around 39-44 MJ/kg
    - Gasoline has energy density of around 42 MJ/kg (32 MJ/l)

- Diesel fuel has energy density of 43 MJ/kg (36 MJ/l)
- Ethanol has energy density of 27 MJ/kg (21 MJ/l)
- Biodiesel as fatty acid methyl ester (FAME) has energy density of 38 MJ/kg (33 MJ/l)
- Uranium fuel has an energy density of around 3,900 MJ/kg based on 3.2 wt% uranium in the fuel

Efficiency and Energy Consumption

11. **Energy consumption to produce a commodity energy product –** measures the energy consumed in producing the commodity energy from each primary resource. It includes the sum of external energy inputs plus energy losses due to inefficiencies.

    Electricity - It takes between 1.2 and 2 GJ of energy to produce one GJ of electricity from hydrocarbon based energy sources. It takes from about one GJ to about six GJ of energy to convert biomass, landfill gas or MSW to electricity. It takes 2.3 GJ of energy to produce 1 GJ of electricity from uranium. Our assumption has been that there is no energy expended to produce electric power from wind or solar, although in the case of wind, there may be measureable parasitic power consumption to operate the wind farm. We have not included the energy to make the wind turbine or the solar panel in the same manner that we have not included the energy to set up a coal mine, a bitumen upgrader, or an ethanol fermentation plant.

    Transportation fuels – It takes around 0.1 GJ of natural gas to produce one GJ of transportation fuel and around 0.4 GJ of oil to produce one GJ of transportation fuel. It takes around one GJ of biomass to make one GJ of transportation fuel as ethanol and 0.2 GJ of biomass to make one GJ of biodiesel.

    Heat – It takes from 0.2 to 0.3 GJ of hydrocarbon-based energy to make one GJ of heat. It takes 0.2 GJ of biomass in anaerobic digestion to make one GJ of heat and 0.3 GJ of landfill biomass to make one GJ of heat. It takes 0.2-0.7 GJ of biomass to make one GJ of heat from biomass combustion and MSW.

12. **Net Energy Ratio –** measures the net commodity energy that can be produced from a primary energy source, including all the energy needed for this conversion to commodity energy. It is defined as the energy in the commodity divided by the energy to convert the primary resource to the commodity plus the energy in the primary source.

    Electricity – The net energy ratio of electricity from coal, oil, nuclear, and anaerobic digestion is in the range of 0.2 GJ of commodity energy produced per GJ of primary energy plus the energy to convert the primary energy to commodity energy, including losses. It is around 0.3 for electricity from wind and from natural gas. This ratio is over 0.7 for electricity from hydro and around 0.1 for electricity from biomass combustion, and solar.

Transportation fuel – The net energy to produce transportation fuels from oil is 0.6 and 0.8 for natural gas. For biofuels, the net energy ratio is 0.3 for biomass to ethanol and 0.7 for biomass to biodiesel.

Heat – The net energy ratio to produce heat from hydrocarbon based energy sources ranges from 0.6 to 0.7. For biomass combustion it is 0.4; it is 0.5 from MSW, and 0.7 from anaerobic digestion.

14. **Distance Delivered –** measures how far a designated vehicle can travel per GJ of commodity energy. The designated personal use vehicles are measuring devices to enable comparisons. They are: a VW spark ignition engine for gasoline, ethanol, and natural gas; a VW diesel compression ignition engine for diesel and biodiesel; and a Nissan Leaf battery powered plug in electric vehicle for electricity.

    Electricity – Coal and oil deliver close to 500 km from each GJ of primary energy when converted to electricity Natural gas delivers 580 km from each GJ of primary energy. Nuclear delivers around 270 km per GJ; for wind the distance delivered is about 380 km per GJ. Biomass converted to electricity delivers between 200 and 350 km per GJ of commodity energy. Solar delivers about 100 km per GJ of primary energy when converted to electricity.

    Transportation fuel – Both oil and natural gas deliver around 290 km per GJ of primary energy. Biomass delivers around 370 km/GJ as biodiesel from canola oil and around 170 km/GJ as ethanol produced via fermentation of biomass.

Environmental Metrics

15. **Greenhouse gas emissions** –estimates the GHG emissions for converting the primary energy to commodity energy, thereby providing a measure of the global warming potential of the path from primary energy source through delivery and use of the produced commodity energy.

    <u>Electricity</u> – Electricity from coal has a GHG emission intensity around 280 g CO_2e/MJ of electricity. Electricity from oil is around 230 g CO_2e/MJ of electricity and from natural gas it is around 125 g CO_2e/MJ. We assume that wind and solar have no GHG emissions associated with electricity production. Electricity from MSW, landfill, and anaerobic digestion have nil net GHG emissions. Hydro has a GHG footprint around 40 g CO_2e/MJ of electricity – primarily as a result of the land use impact, which includes the loss of CO_2 sequestration in biomass that is covered by the reservoir.

Transportation – The well to wheels GHG emission intensity for converting oil to transportation fuels is on the order of 99 g CO_2e/MJ of transportation fuel – which includes the GHG emissions from oil production, transport, refining to products, and combustion of the fuel onboard the vehicle. It is 64 g CO_2e/MJ of natural gas. It is around 30 g CO_2e/MJ of biodiesel and 100 g CO_2e/MJ of ethanol. These assessments include the GHG land use impact of each fuel pathway.

Heat – The GHG emission intensity of heat from natural gas, oil, and coal range from 80-120 g CO_2e/MJ of heat. We assume no net GHG emissions for heat from biomass, landfill gas and MSW.

16. **Land Use –** measures the land used in the process of extracting the resource and by the land occupied by the conversion facility.

    Electricity – the land use impact of electricity is only significant for hydro and utility based-solar, which uses solar panels installed on land rather than on rooftops. For hydro, the land use impact of electricity generation is around 5 ha/PJ of electricity. For utility based solar the land use impact is about 750 ha/PJ of electricity.

    Transportation fuel – land use for the production of transportation fuel via ethanol fermentation of grain is on the order of 45 ha/PJ of transport fuel. It is around 25 ha/PJ for biodiesel from canola. For gasoline and diesel from oil, the land use impact is 0.003 ha/PJ of transportation fuel.

    Heat – the land use impact of generating heat from coal is on the order of 0.02 ha/PJ, which is about the same as for biomass combustion. It is less than 0.002 ha/PJ for oil and even less for natural gas.

17. **Water Use -** measures the amount of water to produce a commodity energy

    Water use is significant for hydro, over 40 m^3/PJ for electricity generation, mainly the result of evaporation from the reservoir. For the other energy sources, water use is between 0.1 m^3/PJ of electricity (wind) to nearly 0.6 m^3/PJ of electricity for coal and 0.5 m^3/PJ for nuclear.

20. **Biodiversity** – is an important and complex issue in resource project development.

    Biodiversity is a measure of variability in a given ecosystem but is difficult to quantify as a metric similar to the other metrics that we have used in the Study because biodiversity attributes are highly location- and development-specific. In addition, development projects that could negatively affect biodiversity may be ameliorated through sustainability action plans specific to the project, such as species conservation plans. We did not include biodiversity assessment as a quantitative metric in this Study.

Observations

Examining energy in an Alberta context requires understanding the particular characteristics of each energy sector as well as the dynamics of the rapidly changing energy environment. Three characteristics of the energy sector in Alberta we believe are important in understanding the nature of the energy in Alberta.

- **First:** Alberta is a province with relatively low population density, a high degree of industrialization, and a resource-intensive economy. Much of the energy in Alberta supplies industrial demand, especially in oil sands production, and there is continued high growth in industrial demand for energy, especially heat. Energy demand in the Province is dominated by the need for high intensity, high quality sources of heat to support the oil sands industry, which is export oriented. Growth in demand for energy for the oil sands area is greater than in other sectors of the economy, which means that the demand for high temperature sources of heat will continue to outstrip demand for relatively low temperature heat for space heating.

  While Alberta's geothermal resources are abundant, they are relatively low temperature and not suitable to provide direct high temperature heat for in situ bitumen production or process heat for natural gas clean up, bitumen upgrading, oil refining or petrochemical production. High temperature sources of heat can be supplied by direct combustion of fuels – especially natural gas - or on a longer time horizon, potentially from nuclear.

- **Second:** Alberta has abundant and diverse energy resources. Much of the oil and natural gas-based energy is exported to other provinces and to the US. The availability of hydrocarbon based resources such as coal and bitumen far outstrip provincial demand. The potential large reserves of unconventional gas and oil will likely continue to position Alberta as an export oriented energy industry.

  The oil refining infrastructure is more than sufficient to meet provincial demand for transportation fuels from oil. In the electricity sector, significant capital investments will be required over the coming decades to either replace coal-fired power plants or add carbon capture and storage (CCS) to coal-fired plants in order to meet federal GHG requirements. In addition, investment will be needed to improve the electrical supply grid to meet the requirements of a stable electricity supply as more intermittent sources such as wind and distributed solar supply the grid, and to meet the demand for electricity from the continued growth in Alberta's Industrial Heartland.

Alberta is essentially an energy island as a result of its relatively small internal market and the geographic isolation of the Province. Unlocking the full potential of its resources, will mean that Alberta must continue to look to markets outside of the Province while overcoming infrastructure and regulatory hurdles to energy exports and electricity import.

- **Third:** As Alberta, Canada and the global economy move toward a more carbon constrained environment, Alberta is committed to reducing carbon emissions and lowering carbon intensity. These goals can be difficult to achieve in a region with a high degree of industrialization and a burgeoning fossil fuels industry and relative geographic isolation from other markets – especially electricity markets.

To meet the environmental constraints, Alberta must develop energy resources that can meet the demands of its industrial market while also lowering the carbon intensity and other environmental impacts of its energy supply. In particular, we see this in the electrical sector in which federal GHG legislation has mandated that Alberta reduce emissions from coal fired power plants by either implementing carbon capture and storage (CCS) or by using lower-carbon-intensity sources of electrical power.

We expect this shift in electricity generation not to be monolithic in nature, but rather a move toward a more diversified electric power supply portfolio. The nature of this portfolio likely will reflect the trade-offs between the different power supply pathways. For example, wind power provides electricity with very low GHG emissions but because it is variable in nature it will require back-up from other dispatchable sources of electricity, which are often stock-based sources of electric power such as natural gas, coal, or possibly nuclear, or on a longer time horizon may even include geothermal or large-scale energy storage.

We foresee natural gas as playing a much larger role in electric power generation due to its lower carbon footprint and high capacity factor. On the supply side, greater development of unconventional natural gas reserves will enable Alberta to meet its increased demand for low-GHG-emission, dispatchable electricity supply as well as the increased demand for high temperature energy to enable growth in oil sands production.

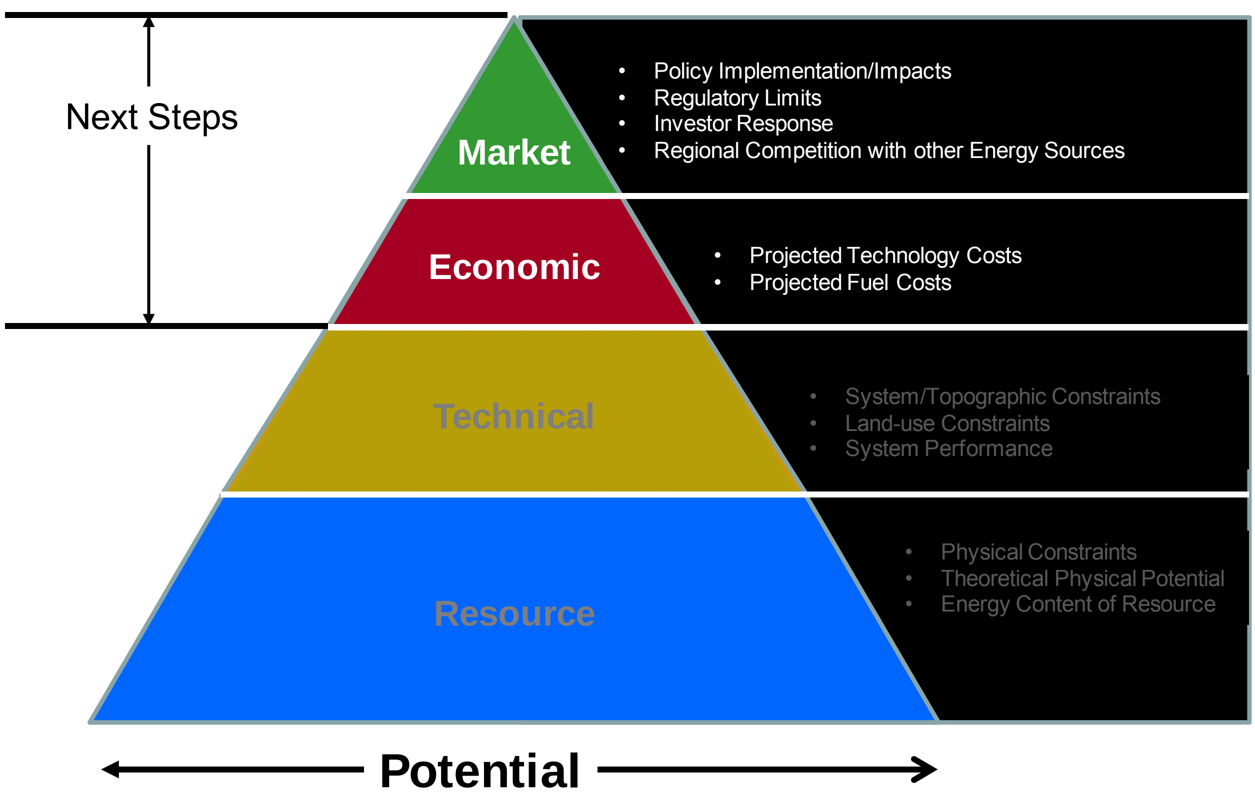
The changing nature of the electrical power supply portfolio also will require changes to the electrical grid in Alberta so that the increasingly diverse and variable sources of electric power can be accommodated without compromising the supply of stable high quality electric power.

Next Steps

The focus of this Study has been on understanding the resources and technical potential and constraints of the energy supply in Alberta without taking into account economics or public policy. As we have analyzed the potential feasibility of energy supply to Alberta we have ignored the fact that some of the energy pathways considered are not currently implemented or have not been broadly implemented because they are not economically feasible. In addition, certain technologies may not be implemented or may be shut down for policy reasons.

It is clear that any analysis of Alberta's energy potential is incomplete without including an assessment of economics and public policy. To do so we must shift our focus to the upper two sections of the energy pyramid described earlier – the economic and market factors that will provide further understanding about the constraints and direction of energy development and deployment in Alberta. (See Figure 8.1)

Figure 8.1
Pyramid of Stages for Energy Supply Evaluation



Source: National Renewable Energy Laboratory (NREL), 2012

Economics and Regulations

Several examples of economic and regulatory issues that are likely to affect energy resource development in Alberta include the following:

- Hydroelectric power – Two identified major dam sites in Alberta have not moved forward in the development process. Hydroelectric power is attractive because of its low greenhouse gas emissions and because it is dispatchable. However, hydro projects have languished due to environmental opposition to land use changes inherent to reservoir-based hydroelectric development and difficulties in financing major capital investment in power production that will not pay out for many years.
- Nuclear power - A potential site for a nuclear power plant near Edmonton has been considered in the past. There has also been support for nuclear power to provide low carbon intensity energy for SAGD sites. However, none of these projects were implemented for multiple reasons including economics, project financing, difficulty in finding appropriate sites, and local opposition.

Providing a complete picture of energy potential in Alberta, will require fully describing the economics and costs of developing each potential energy resource. It will also require fully assessing the regulatory environment in Alberta as well as at the federal and international level. The energy sector crosses both inter-provincial and international borders and regulatory developments outside of Alberta and Canada will continue to affect the Alberta energy sector. Resource potential and the ability to develop energy commodity production projects should be analyzed using scenarios and risk assessment tools to understand how future regulations may affect each source.

The next steps in understanding the potential energy supply in an Alberta context must include an economic and market analysis of resources and pathways for energy in Alberta as well as an analysis of potential provincial, federal and international regulations and export opportunities and infrastructure needs.

Energy Transport

Alberta has abundant and diverse reserves of energy in existing, identified hydrocarbon-based resources and potential non-hydrocarbon-based resources such as wind and solar. With the magnitude of hydrocarbon-based resources in Alberta such as coal and bitumen far outstripping provincial demand and its geographic isolation and land locked position, Alberta is essentially an island that is rich in energy resources. Unlocking the full potential of its resources will mean overcoming hurdles to energy exports and limits on GHG emissions from energy sources.

Overcoming the barriers to energy development will require oil and gas routes with access to markets south, east and west of Alberta. Pipeline projects have been proposed and steps are being taken to overcome regulatory hurdles. Rail routes for oil are being expanded. Some of the barriers to bitumen export via pipeline result from the need to overcome viscosity and density limits imposed by pipeline shippers, which requires either dilution of bitumen with a lower boiling material or conversion to a bottomless synthetic crude oil. New technologies being considered to overcome bitumen shipping infrastructure limits include partial upgrading of bitumen, and shipment of hot undiluted or less diluted bitumen by rail. A comprehensive identification of scenarios and risk assessment of potential systems for bitumen export will help identify potential limitations to the development of the bitumen resource in Alberta.

Increased production of refined products from Alberta oil and bitumen resources could be another route to add value. However, this option will require increased export of refined products from the Province that heretofore has not been economically attractive and will likely require new transport infrastructure. Exploitation of new sources of natural gas could also be attractive, if there were ways to bring this material to world markets, which will likely include new pipelines and LNG facilities at coastal locations.

Another example of infrastructure to meet the diverse portfolio of future energy for Alberta will be to increase integration of the regional electrical grid system with Saskatchewan, British Columbia and the US power grids which may enable greater exploitation of Alberta's plentiful supply of wind.

Technology Development

A key observation from this Study is that the supply of energy in Alberta is rich and varied Different energy resources and pathways provide different benefits and challenges. As a result of new regulations limiting CO_2 emissions from electricity generation, Alberta will need to change from a highly coal-based electricity supply to one that has lower GHG emission intensity. A second observation is that Alberta has abundant supply of hydrocarbon-based energy sources. The Province is a significant exporter of natural gas, bitumen-based oil, and conventional oil and Alberta has large reserves of coal. A third observation is that Alberta has significant potential for wind-based and solar-based electricity supply, but that managing the intermittent and variable nature of these energy sources is likely to limit their deployment. A fourth observation is that Alberta is not likely to meet its energy needs with bio-based energy or with hydro-based electricity. New hydroelectric generation capacity is expensive with significant land impact. Bio-based energy from crops or wood is too small of a resource to have much impact on Alberta's total energy needs. Further, diverting land to energy use will affect food production. Using landfill gas, gas from anaerobic digestion and MSW as energy sources makes sense to reduce the impact of waste disposal, but these resources are too small to supply much energy for Alberta. Geothermal-based energy suffers from underground temperatures that are low. Nuclear energy is limited because of cost, perceptions about safety, and waste disposal/storage issues.

Fully developing the potential of these varied resources within economic, policy and regulatory constraints will require technology developments and innovations. In particular, we see the several areas of technology development as key to the successful future development of Alberta's resources.

Unconventional hydrocarbon resource development

Reducing the GHG emission intensity of electricity production with dispatchable power generation, providing backup for wind and solar power, and additional energy for bitumen extraction will require more natural gas. Significant potential exists to produce light oil and natural gas from shale formations, in the same manner as has been done in the Barnett, Haynesville, Bakken, Eagle Ford and Marcellus formations in the US. Adoption of new exploration and development technologies and new drilling technologies will enable Alberta to unlock the potential for tight oil and gas and shale oil and gas. These technologies have the potential to significantly increase Alberta's established reserves in both natural gas and oil and provide future supply for both energy export and use of natural gas for electricity generation and in situ bitumen production in the province.

Electricity storage and enhanced grid technology

Deployment of low carbon electricity sources such as wind and distributed solar photovoltaics is limited by the intermittent and variable nature of these sources. While natural gas fired power plants can provide backup when these resources are not producing electricity, energy storage provides a way to capture the surplus energy from wind and solar. Development and adoption of energy storage and enhanced grid technologies will enable higher penetration of these technologies while maintaining grid stability and delivering low GHG intensity electricity to meet demand.

Geothermal technology

Alberta's geothermal resources are at temperatures too low to directly generate high temperature heat. Low temperature heat could be used for space heating based on heat pumps. However, because of its climate, the demand for air conditioning is low, which reduces the economic incentive for geothermal space heating/cooling in Alberta. Also, the current high carbon intensity electric grid in Alberta means that geothermal heat pumps do not have a significant GHG emissions benefit over natural gas based space heating. Improving the efficiency of geothermal energy capture could further the use of this low level source of heat. Reducing the carbon intensity of the electrical grid could provide incentive for more widespread adoption of geothermal technology. Improvements in drilling technology to recover tight oil and gas will lead to improvements in capturing geothermal heat.

Carbon Capture and Storage

To date, the economics of CCS have not been conducive to capturing and disposing of CO_2 resulting from energy use. If storage technology were proven to be robust and the economics for CCS could be improved sufficiently, coal might become an attractive source of electric power.

Nuclear Power

Reducing the cost of nuclear power plants may make this energy source more attractive. Smaller, modular plants could better match Alberta's energy needs. Robust safety and security systems and waste management that overcome society's objections to nuclear power could further enable deployment of this very low GHG emissions energy source.

Demand Reduction

Critical to managing energy in Alberta is the continued drive to reduce provincial energy intensity. Technologies to reduce demand through efficiency improvements can improve energy intensity in all sectors. In the residential and commercial sector, technology improvements can reduce energy use by the adoption of more efficient lighting, appliances, and space heating. In transportation, engine efficiency improvement and technologies to reduce tire resistance and vehicle weight will decrease fuel demand on a kilometer-driven basis. In the industrial sector, technologies to reduce steam use for in situ bitumen production, to improve heat integration and to use lower carbon fuels will decrease energy demand and lower carbon emissions.

Timing

We opine that within the twenty-year time horizon of the Study, many incremental improvements that we have discussed throughout this report could take place in all sectors of Alberta's energy industry. Technology breakthroughs may occur at any time. However, the probability of success in major new technology development is likely much lower than for incremental improvements to known technology. An example would be the continuing struggle to commercialize biofuels based on cellulose conversion by novel organisms versus continuing improvement in conventional sugar fermentation technology. Thus in the time horizon of the Study, we might not expect to see a large number of energy conversion breakthroughs.

We have attempted in this Study to examine energy within an Alberta context to better understand the particular characteristics of each energy resource that now or in the future could supply the energy needs of Alberta and its energy export market. Many of these energy sources are undergoing rapid change. New sources are being developed. Some sources may be curtailed without new technologies to reduce their societal impact. Regulations on energy use and especially its environmental impact will undoubtedly change Alberta’s energy portfolio. While we neither addressed the economics of energy production nor the rate of new energy resource deployment in this Study, we well know that the next step in understanding Alberta’s energy endowment will be to go beyond the boundaries of this Study, to next address the economic and market issues that affect energy.

Section 9.

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